Refinement of Selected Fuel-Cycle Emissions Analyses

Final Report

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List of Terms and Abbreviations

AGA	American Gas Association
AP-42	EPA document on emission factors
atm	1 atmosphere = 14.7 psi
EMFAC	ARB model for determining vehicle g/mi emissions
API	American Petroleum Institute
ARB	California Air Resources Board
bbl	barrel of crude oil (42 gal)
Bcf	billion standard cubic feet
bhp-hr	brake horsepower hour (dynamometer measurement)
Btu	British thermal unit
bsfc	brake specific fuel consumption
CA	California
CEC	California Energy Commission
CES	Category Emission Source
CHP	California Highway Patrol
CNG	compressed natural gas
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
DOE	United States Department of Energy
DWT	dead weight ton
EMA	Engine Manufacturers Association
EMFAC	ARB vehicle emissions factor model
EVs	electric vehicles
FCC	fluid catalytic cracker
FE	Fuel economy
FFV	flexible fuel vehicle
FTD	Fisher Tropsch Diesel
GWh	gigaWatt hour = 1,000,000 kWh
GRI	Gas Research Institute
GVW	gross vehicle weight
HHV	higher heating value of fuel or feedstock
hp-hr	shaft horsepower hour
IC	internal combustion
IGT	Institute for Gas Technology
kg	kilogram
kWh	kilo-Watt hour
LACMTA	Los Angles County Metropolitan Transportation Authority
LADWP	Los Angeles Department of Water and Power
LFG	landfill gas
LHV	lower heating value, HHV less heat of vaporization of water vapor in combustion products
LPG	liquefied petroleum gas
H_2	hydrogen
g	grams

gal	gallon
g/bhp-hr	grams per brake horsepower-hour
MWh	megaWatt hour
mi	mile
MMBtu	Million Btu
MMscf	Million scf
MTBE	methyl tertiary butyl ether
mpg	miles per gallon
MW	molecular weight
MY	model year
NFPA	National Fire Protection Association
NGV	natural gas vehicle
NMOG	non-methane organic gases
NO_x	oxides of nitrogen
NPGA	National Propane Gas Association
NRDC	National Resources Defence Council
NREL	National Renewable Energy Laboratory
NSPS	new source performance standards
O_3	ozone
OEM	original equipment manufacturer
POX	partial oxidation
psi	pressure, lb/in^2, 14.7 psi = 1 atm
QF	qualifying facility (power generator)
RECLAIM	Regional Clean Air Incentive Market
RFG	reformulated gasoline
ROW	rest of world
RVP	Reid vapor pressure
SoCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
scf	standard cubic feet of gas, at 60°F and 1 atm
SCR	selective catalytic reduction
scfm	standard cubic feet per minute
SO_x	oxides of sulfur
SR	steam reformer
SRWC	short rotation woody crops
t/d	tons/day
TAME	tertiary amyl methyl ether
TBA	tertiary butyl alcohol
TEOR	thermally enhanced oil recovery
THC	total hydrocarbons
ton	United States short ton, 2000 lb
TOG	total organic gases
TVP	true vapor pressure
UG	underground

U.S. EPA	United States Environmental Protection Agency
ullage	liquid fuel tank vapor space
V_e	equilibrium vapor
WLPGA	World Liquid Propane Gas Association
WSCC	Western System Coordinating Council
WSPA	Western States Petroleum Association

Executive Summary

Emissions associated with the production and distribution of fuels can be significant in comparison with tailpipe and exhaust emissions. Examining these fuel-cycle emissions for alternative-fueled vehicles appears relevant when assessing the overall environmental impact of these vehicles from both a global and local perspective.

This study determines oxides of nitrogen (NO_x), non-methane organic gases (NMOG), toxics, carbon monoxide (CO), and carbon dioxide (CO_2) emissions for methanol, diesel, LPG, and electric vehicle operation. Reformulated diesel and synthetic diesel were also analyzed. These fuel options are of interest because they potentially result in relatively low refueling emissions. The purpose of the study is to investigate those fuels that might be categorized as having low fuel cycle emissions. Vehicles operating on 100 percent methanol, LPG, and diesel were judged by ARB to result in fuel-cycle NMOG emissions that are close to 0.01 g/mi. Fuels with clearly lower fuel cycle emissions such as CNG and hydrogen are not analyzed in this study. Gasoline was also not analyzed as the results of a 1996 fuel-cycle study indicated NMOG emissions around 0.03 g/mi (Unnasch 1996). These results do not reflect improvements that could be achieved with advanced gasoline hybrid vehicle technologies and further investigation is warranted.

Emissions considered in this study are those associated with the operation of extraction, production, and distribution equipment. Emissions associated with the production or decommissioning of facilities or vehicles are not evaluated. Emission calculations are based on vehicle operation in the South Coast Air Basin and the fuel-cycle emissions are allocated according to where they occur including a summation of emissions within only the South Coast Air Basin.

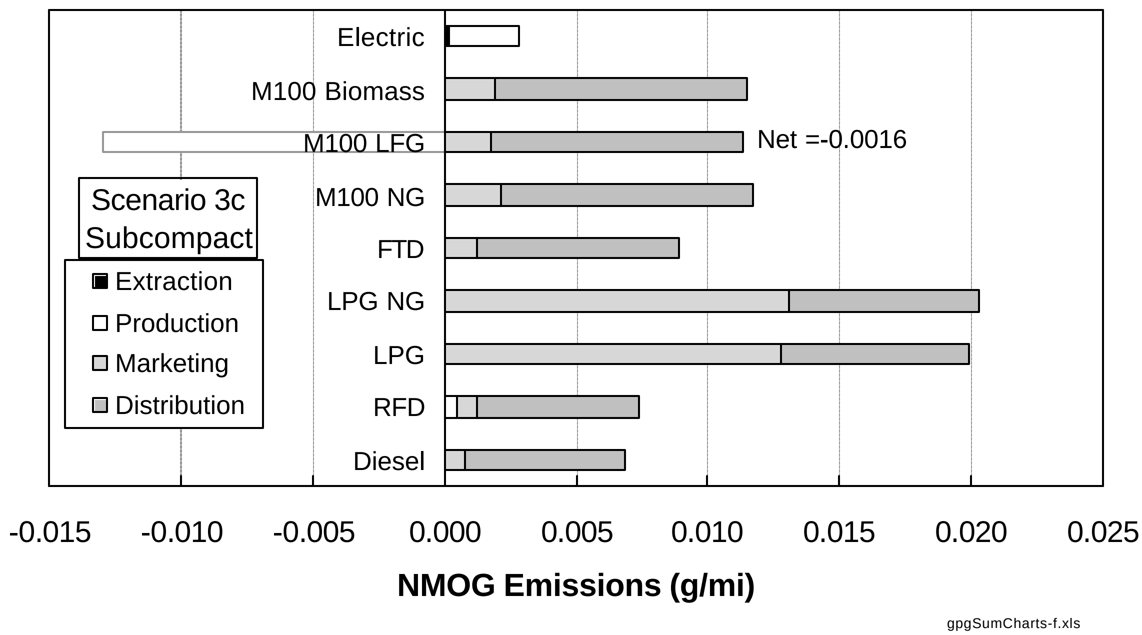
Fuel-cycle emissions vary substantially based on factors such as the time-frame under consideration, vehicle fuel economy, the degree of emission control, amount of fuel produced and processed within the South Coast Air Basin, and assumptions regarding feedstock sources. Another important consideration is whether average emissions for all fuel production or marginal emissions for the production of the last unit of fuel are of interest. This study considers marginal emissions in the late 1990s and 2010 time frames.

Marginal Fuel-Cycle Emissions

Small increments of alternative fuel use would result in emissions from fuel hauling, vehicle fueling, and marine vessels or rail cars used to import fuels or crude oil. On a small scale, other market conditions will influence refinery emissions more substantially than gasoline displacement due to alternative fuel use, leaving the refineries in the South Coast Air Basin operating at capacity. Many of the fuels considered in this study will be produced outside the South Coast Air Basin. Due to the location of fuel production as well as emission regulation considerations that apply to the South Coast Air Basin, marginal emissions primarily correspond to fuel trucking or distribution and local vehicle fueling. Marginal fuel cycle NO_x is uniformly low for all vehicle fuels

(Unnasch 1996, ARB 2000). Figure S-1 shows the marginal fuel cycle NMOG results for subcompact vehicles considered in this study. These results correspond to the favorable set of assumptions that are consistent with all fueling infrastructure complying with revised rules for fuel distribution. A sensitivity analysis on key assumptions was also performed.

Figure S-1: Marginal NMOG Emissions Within the South Coast Air Basin for subcompact vehicles



These results are highlighted because the study focuses on emissions that are consistent with stationary source emission requirements. Electricity for EVs operated in the South Coast Air Basin will be generated in the basin, the rest of California, and outside of California. The analysis in this study indicates that marginal power generation for EVs is primarily generated from natural gas. Marginal emissions from power generated in the South Coast Air Basin are limited primaily to NMOG emissions from natural gas fired power plants. Generation sources such as landfill gas, biomass, hydroelectric, and nuclear are not considered marginal sources since these facilities operate with or without additional load from EVs. Furthermore, existing facilities in the South Coast Air Basin may not increase emissions beyond current permit levels and new facilities would need to buy Emission Reduction Credits (ERCs) or offsets. Power plants in the South Coast Air Basin are subject to RECLAIM that provides a cap on power plant NO_x emissions for each utility. Power generation for EVs in 2010 will result in zero additional incremental NO_x in the South Coast Air Basin[1] due to RECLAIM limits. The case for zero marginal power plant NO_x does, however, depend upon the successful use of ERCs.

Incremental emissions from diesel and reformulated diesel distribution correspond to about 0.004 g/mi of hydrocarbons and 0.001 g/mi of NO_x from delivery trucks. There would be zero impact on refinery NO_x or hydrocarbon emissions as additional refinery capacity is generally subject to an emission cap. If diesel, crude oil, or methanol imports were rising to meet vehicle demand, resulting NO_x emissions would be below 0.01 g/mi from marine vessel operations in the South Coast Air Basin. The case for zero marginal refinery NO_x also depends on the continued cap on NO_x emissions in the RECLAIM program.

Methanol is a candidate fuel for fuel cell powered vehicles because it can be converted to hydrogen on-board a vehicle more simply than hydrocarbon fuels. The projected fuel economy of methanol powered fuel cell vehicles with on-board reformers is considered in these results. NMOG emissions are slightly above 0.01 g/mi for subcompact vehicles; however, for vehicles with fuel economy above 27 mpg (54 mi/equivalent gasoline gallon), the NMOG value drops below 0.01 g/mi.[2] The fuel cycle emissions depend largely upon refueling spillage emissions. Larger vehicle fuel tanks or alternative fueling equipment could reduce spillage emissions. NMOG emissions for LPG subcompact vehicles are above 0.01 g/mi. The values presented in Figure S-1 assume that LPG venting is eliminated throughout the distribution chain including delivery trucks and service station tanks.

Other fuel options not considered in this study could also result in low fuel-cycle emissions. For example, fuels such as low vapor pressure hydrocarbons used as fuel for fuel-cell-powered vehicles should be evaluated.

Average Fuel-Cycle Emissions

Diesel production and distribution results in higher average NO_x emissions than alternative fuel production and distribution (except for electricity) since petroleum is refined in the South Coast Air Basin. The average fuel cycle NO_x emissions for electric power production for electric vehicles are about the same as the fuel cycle emissions from diesel production. Average emissions; however, are not considered relevant in air quality debates as these emissions include sources that would not vary with changes in fuel demand.

[1] The Regional Clean Air Incentive Market places declining caps on NOx emissions from large sources such as power plants and oil refineries.

[2] A gallon of methanol contains half the energy of a gallon of gasoline. Therefore a methanol vehicle with a fuel economy of 54 miles per equivalent gasoline gallon achieves 27 miles per actual gallon.

CO_2 emissions from fuel production and vehicle use are also important due to their contribution towards the accumulation of greenhouse gases. These emissions were calculated for the fuel options considered in this study.

Uncertainty Analysis

The uncertainty in fuel cycle emissions is indicated in Table S-1. The potential variation in emissions is indicated for each of the emission sources. These uncertainties are unlikely to occur simultaneously. The uncertainties are different for different fuels depending upon factors such as the fuel's vapor pressure. In the case of LPG, the dominant uncertainty is whether vapor controls that eliminate tank venting will be required throughout the distribution chain. Refueling spillage is the largest uncertainty. If refueling emissions are consistent with those from new gasoline equipment, then the uncertainty would be much smaller.

Table S-1. Marginal NMOG Emissions Within the South Coast Air Basin

	Estimated Uncertainty (g/gal)			
Source	**RFD**	**Methanol**	**LPG**	**Electric**
NMOG Spillage	0.002	0.0017	0.002	0
Subcompact fuel economy	0.0002	0.0004	0.0002	0.0003
Fuel storage, dispensing	0.00004	0.0006	0.013	0
Tank truck distance	0.00002	0.0003	0.0003	0
Power plant/refinery	0.0004	0	0	0.0026[b]
Total uncertainty[a]	0.0020	0.0019	0.013	0.0026[b]

[a] Total uncertainty is calculated on a root-mean-square (RMS) basis which is based on the uncertainties in emission factors, fuel economy, and scenario assumptions being random and independent. High spillage emissions are not consistent with expected refueling standards but are shown here to illustrate the potential emissions.

[b] Uncertainties include fraction of generation in the SoCAB NMOG emission factor, transmission losses, and power plant heat rate (which is a surrogate for time of day charging).

1. Introduction

As emissions from passenger cars are reduced, emissions from vehicle refueling, fuel transportation, processing, and feedstock extraction represent a larger share of the total emissions that are attributed to vehicle operation. Quantifying these fuel-cycle emissions is an important aspect of assessing the total emissions impact of vehicle operation. This project builds upon the 1996 Acurex study, “Evaluation of Fuel-Cycle Emissions on a Reactivity Basis” (Unnasch 1996), with the purpose of examining uncertainties and further document assumptions.

1.1 Background

Although significant strides have been made toward improving California’s air quality, health-based state and federal air quality standards continue to be exceeded in regions throughout California. Areas exceeding the federal 1-hour ozone standard include the South Coast Air Basin (SoCAB), San Diego County, San Joaquin Valley, the Southeast Desert, the Broader Sacramento area, and Ventura County. With promulgation of the new federal 8-hour ozone standard, more areas of the State are likely to be designated as nonattainment. Ozone (created by the photochemical reaction of reactive organic gases (ROG) and oxides of nitrogen (NO_x)) leads to harmful respiratory effects including lung damage, chest pain, coughing, and shortness of breath, especially affecting children and persons with compromised respiratory systems. Other environmental effects from ozone include crop damage. In addition, because ozone precursors, such as NO_x, also react in the atmosphere to form particulate matter (PM), reductions in NO_x will be crucial to meet existing state and federal PM_{10} standards, as well as the new federal standards for fine particulate matter ($PM_{2.5}$).

California’s plan for achieving the federal 1-hour ozone standard is contained in the California State Implementation Plan (SIP) that was approved by the ARB in 1994 (ARB 1994). A significant part of the SIP pertains to the control of mobile sources, which are estimated to account for approximately 60 percent of ozone precursors statewide. The SIP calls for new measures to cut ozone precursor emissions from mobile sources to half of what the emissions would be under existing regulations

The pressing requirements for meeting air quality attainment goals have brought about amendments to ARB’s Low Emission Vehicle (LEV) standards with the LEV II standards (ARB 1998, ARB 2000b). The LEV II regulations will help achieve and maintain the federal 1-hour ozone standard in regions such as the San Joaquin Valley and the Sacramento area, the federal 8-hour ozone and particulate matter in a number of areas, and the state ozone and particulate matter standards throughout California.

The LEV II standards include a new emission standard category — Super Ultra Low Emission Vehicle (SULEV) for passenger cars and light trucks. A variety of vehicle technologies can reduce emissions to meet these levels. Vehicles powered by fuel cells, hybrid electric drive trains, or advanced internal combustion (IC) engines could qualify to meet ARB’s SULEV standard.

ARB's revised ZEV program allows for additional flexibility to broaden the scope of vehicles that could qualify for meeting some portion of the ZEV requirement. Vehicles can qualify for partial ZEV (PZEV) allowances that could be used to meet the ZEV requirement. The applicable PZEV allowance for each vehicle type would be determined based on a set of criteria designed to identify and reward ZEV-like characteristics in a variety of advanced-technology vehicles. In order for it to receive any PZEV allowance, a vehicle would need to satisfy the requirements for receiving the "baseline ZEV allowance." To receive this allowance, the vehicles would need to meet SULEV standards and also satisfy both second-generation on-board diagnostics requirements and zero fuel evaporative emission requirements. Vehicles that meet these requirements would be granted a 0.2 PZEV allowance. An additional allowance up to 0.6 is provided for vehicles realizing zero emissions potential with an extended range. This allowance could apply to hybrid electric vehicles with battery-only driving capability or fuel-cell-powered vehicles with nil emissions.

In addition, vehicles that use fuels with very low fuel-cycle emissions can receive a further ZEV allowance up to 0.2. The fuel-cycle emissions associated with a particular fuel are the total emissions associated with the production, marketing, and distribution, in grams per unit fuel. The marginal NMOG emissions associated with the fuel use by the vehicle must be lower than or equal to 0.01 grams per mile. The 0.01 g NMOG/mile low fuel cycle emissions historically evolved from emission levels that were considered to be equivalent to those from battery powered electric vehicles. The California Energy Commission (CEC) analyzed power plant emissions in 1995 and reported NMOG of about 0.01 g/mi (Tanghetti 1995). These emissions were determined on the basis of emissions in the SoCAB per kWh generated in the SoCAB. At the time of this study, EV energy consumption was estimated to be 0.28 kWh/mi. Subsequent emission policy discussions focused on the metric of emissions in the SoCAB per <u>total</u> kWh consumed by the EV (Unnasch 1996).[3] For the purpose of providing the ZEV allowance, fuel-cycle NO_x emissions are not considered in the determination, since marginal NO_x emissions for virtually all fuels are expected to be uniformly low.

Fuels with low fuel-cycle emissions and high fuel economy have the potential for meeting ARB's ZEV requirements. This study includes refined estimates of emissions from fuel production and distribution processes and develops estimates for year 2010 fuel-cycle emissions. The assumptions and uncertainties in fuel-cycle emissions were examined in order to identify uncertainties and expected ranges in emissions. Fuel economy for advanced vehicle technologies was also evaluated in order to determine gram per mile emissions. The results, which are presented in this report, can be used to evaluate whether qualifying vehicle technologies meet the requirements of ARB's partial PZEV allowance.

[3] The 0.28 kWh/mi value is lower than today's estimates for subcompact Evs in 2010. The calculation of emissions in the SoCAB per total kWh consumed results in EV NMOG emissions below 0.01 g/mi

1.1.1 Emission Standards

ARB has developed emission standards that take into account fuel cycle emissions for the lowest emitting category of vehicles. The Low Emission Vehicles (LEV) rule was adopted by the California Air Resources Board (ARB) in 1990. That rule is designed to further the development of low emission technologies. The LEV rule calls for fleet average emission limits and for a percentage of new vehicles in 2003 to be zero emission vehicles (ZEVs). A ZEV is defined as a vehicle that produces no emissions during any operating condition throughout its life. Battery-powered electric vehicles (EVs) and dedicated hydrogen fuel cell vehicles are considered to be true ZEVs. Fuel-cell-powered vehicles with fuel reformers may qualify as ZEV equivalents.

Table 1-1 shows the LEV exhaust standards applicable to all Transitional Low-Emission Vehicles (TLEVs); Low-Emission Vehicles (LEVs); Ultra-Low-Emission Vehicles (ULEVs); and Super-Ultra-Low-Emission Vehicles (SULEVs).

Table 1-1: Existing and Proposed LEV Exhaust Emission Standards (g/mi)

Vehicle Category	Vehicle Durability (miles)	NMOG	Carbon Monoxide	Oxides of Nitrogen	Particulate Matter[a]	Formalde-hyde
TLEV	50,000	0.125	3.4	0.4	NA[b]	0.015
	120,000	0.156	4.2	0.6	0.04	0.018
LEV	50,000	0.075	3.4	0.05	NA	0.015
	120,000	0.090	4.2	0.07	0.01	0.018
ULEV	50,000	0.040	1.7	0.05	NA	0.008
	120,000	0.055	2.1	0.07	0.01	0.011
SULEV	120,000	0.010	1.0	0.02	0.01	0.004

[a]Diesel vehicles only.
[b]NA = Not applicable

Source: ARB 1999

The SULEV category would have two separate useful life mileages: 120,000 miles and an optional 150,000-mile useful life. The 150,000-mile certification would be required for SULEV-certified vehicles to qualify for partial ZEV credits if they met certain criteria. Vehicles that meet this certification can also qualify for a partial ZEV allowance (PZEV). Vehicles that operate with marginal fuel cycle NMOG emissions below 0.01 g/mi can receive 0.2 of the potential 1.0 partial ZEV allowance.

1.2 Project Objectives

The primary objective of this study is to refine estimates of the mass emissions on a per-vehicle-mile basis, for selected vehicle fuels, and for the fuel production and energy conversion portions of the total fuel-cycle, including fuel acquisition and refining, distribution, and refueling. The selected vehicle fuels are diesel fuel and liquefied petroleum gas (LPG) for internal combustion vehicles, and methanol for fuel-cell powered vehicles. Fuel-cycle emissions are compared to those from electricity generation for electric vehicles. The mass emissions of NO_x, NMOG, methane, CO, CO_2, and air toxics are quantified for each fuel and for each phase of the fuel cycle. Emission estimates were made for 1996 as a base year and for the year 2010 based on two different projection scenarios for each fuel, one pessimistic and one optimistic. The uncertainty associated with emissions from every step of each fuel cycle is estimated, and those uncertainties are propagated to develop an overall uncertainty for each fuel.

This study provides a consistent basis for comparing the fuel-cycle emissions from a variety of fuels. LPG- and diesel-fueled IC engine vehicles, as well as methanol-powered fuel cell vehicles, have the potential for meeting SULEV requirements and also for operating with low fuel-cycle emissions. Fuel-cycle emissions were determined for conventional vehicles in a 1996 study performed for ARB (Unnasch 1996). Uncertainties exist for some fuel-cycle emission sources, such as venting from LPG distribution trucks or breathing losses from bulk methanol storage tanks. These are potentially significant sources that would affect whether fuel cycle emissions are below 0.01 g/mi NMOG. In addition, vehicle fuel economy affects fuel cycle emissions as fuel cycle emissions, other than spillage, are proportional to the amount of fuel that is consumed. The higher efficiency of diesel and methanol powered fuel cell vehicles are considered in this study.

Again, the objective of this study, was to evaluate the fuels discussed above. Other fuel options in highly efficient vehicles should be studied to determine if these could result in NMOG emissions below 0.01 g/mi.

Determining the emissions for each step in the fuel cycle requires a careful engineering analysis and, when possible, was based on actual fuel processing equipment experience. Obtaining speciated emissions to quantify the toxic components of hydrocarbon emissions also posed a challenge. The most significant source of hydrocarbon emissions is fuel spillage, refueling vapor losses, and storage tank venting. These emissions and others were analyzed in the context of a significant number of both SULEV and other vehicles operating in the year 2010.

The following sections discuss and review the methods used in this report to estimate and calculate the fuel-cycle emissions.

1.3 Project Approach

The fuel-cycle emissions associated with production and distribution of diesel, methanol, liquefied petroleum gas (LPG), and electricity were evaluated. Each fuel was evaluated based upon production from one or more feedstocks. Diesel and LPG are considered for use in internal combustion engine vehicles. Electricity is assessed for pure ZEVs (battery-only electric vehicles), and methanol is considered for use in fuel cell vehicles with on-board methanol reformers.

The following outline summarizes the steps used in this project:

- Determine the physical characteristics and properties of all the fuels and feedstocks
- Evaluate the chemical compositions of the fuels, feedstocks, and their storage vapors as well as the products of combustion of fuel production equipment
- Outline scenarios for the production and distribution of fuels
- Determine the emissions of NO_x, CO, CO_2, CH_4, and NMOG for the processes involved with each scenario
- Develop per-gallon fuel-cycle emissions estimates
- Estimate vehicle fuel economy
- Compare fuel-cycle emissions on a per mile basis

In this study, fuel-cycle emissions are first determined per unit of fuel, which allows for better comparison with other studies and provides better insight into the origin of the emission estimates. Thereafter, the emissions are related to fuel economy to determine gram per mile emissions. This approach allows other values for fuel economy to be investigated more readily.

1.4 Report Scope

Table 1-2 summarizes the fuel/feedstock combinations that were considered in this study. As indicated in the table, several fuel/feedstock combinations are complicated by the fact that some products are made from the same feedstock and many fuels can be produced from several feedstocks. Different mixes of feedstocks are also used in fuel production. For example, a variety of crude oil sources make up the feedstock for California refineries, and this mixture will change in the future. Methanol is currently produced from natural gas, while production from biomass has been considered as an option for the future. Natural gas is produced from gas fields and a by-product of oil production, and the gas can be used for many purposes, including the manufacture of synthetic liquid fuels or methanol. LPG is produced during oil refining and derived from natural gas liquids, a product of oil and natural gas production. Electricity can be produced from a myriad of feedstocks, which range in CO_2 impact from solar energy to coal.

The alternative fuels listed in Table 1-2 are used to a limited extent in California. Many vehicles have been converted to operate on LPG and manufacturers are beginning to offer purpose built vehicles. Several thousand flexible fuel methanol vehicles (FFV's) have been built as production vehicles for operation in California. FFVs are capable of operating on M85, gasoline, or any mixture of these fuels. Prototype fuel cell cars and buses and over 300 transit buses have also been operated on M100. Electric vehicles will make up a significant portion of California's vehicle fleet as part of ARB's Low-Emission Vehicle program. Expanded use of electric vehicles (EVs) has also been considered as a means of reducing emissions to meeting federal Clean Air Act emission requirements. The feedstocks in Table 1-2 may not all be used in the short term. The significance of feedstock options and combinations of fuels and feedstocks that are addressed in this study are discussed in Section 3.

Table 1-2: Fuels, Feedstocks, and Refining Processes Evaluated in this Study

Feedstocks	Fuels[a]
Crude oil	Diesel, reformulated diesel, LPG
Natural gas	Methanol, synthetic diesel, LPG
Landfill gas	Methanol
Biomass	Methanol
Crude oil Natural gas Coal Biomass Hydroelectric	Electricity

[a]Gasoline, natural gas, hydrogen, and other fuels are not included in the study scope.

For the purposes of this study, fuel-cycle emissions represent fuel extraction, production, distribution, and vehicle conversion as illustrated in the example for diesel processing in Figure 1-1. This definition is often referred to as "well to wheels." The analysis considers the marginal, or incremental gallon (or equivalent fuel unit) consumed in the South Coast Air Basin (SoCAB). In order to help evaluate the impact on air quality, the emissions will be geographically categorized. Energy needed for fuel production in the South Coast Air Basin will also be sorted to count sources that correspond to incremental fuel production.

Fuel-cycle emissions were analyzed over a range of assumptions. The major factors that affect fuel-cycle emissions in this study include the following:

- Vehicle fuel economy (which is proportional to fuel-cycle emissions)
- Reduction in emissions due to stationary control measures in Southern California
- Different alternative fuel production feedstocks and technologies
- Control of vehicle refueling emissions

Emissions were estimated for conditions in 1996 and 2010 with emission regulations, and vehicle fuel economy consistent with these time periods. These estimates serve as upper and lower bounds. Table 1-3 shows the scenarios explored in this study.

Figure 1-1: Fuel-Cycle Emission Sources

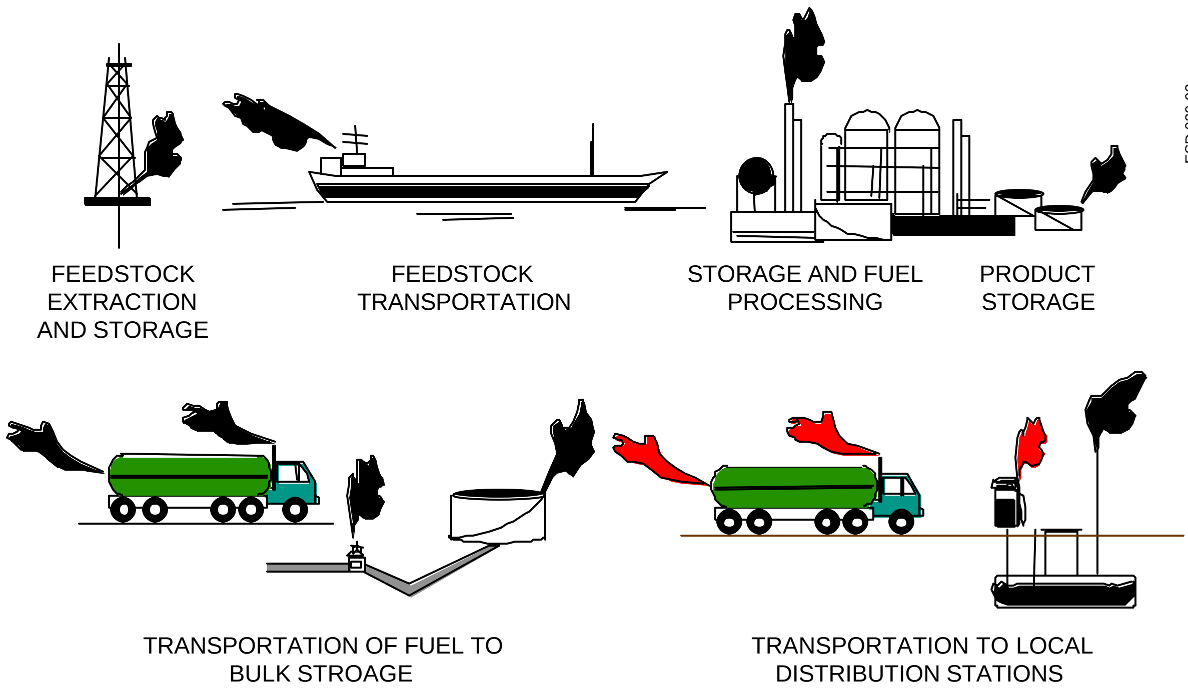


Table 1-3: Scenarios and Timing for Fuel Production and Distribution

Scenario	Year	Description
1 – Pre 2000	1996[a]	Current emissions. Equipment meets prevailing standards. Refinery emissions based on 1997 SCAQMD inventory.
2 – high distribution emissions	2010	Equipment meets standards applicable in year 2010. Emissions consistent with ARB factors for fuel distribution with worst case assumptions for vapor losses and spillage. Higher energy consumption for RFD. Venting emissions from LPG. Railcar transport for methanol from biomass (rather than railcar). More power generation in the SoCAB
3 – base case	2010	Equipment meets standards applicable in year 2010. Emissions consistent with ARB factors for fuel distribution.

[a] 1996 is a baseline year before major refinery modifications. Marginal emissions are not significantly affected between 1996 and 2000.

A significant fraction of the new vehicle mix in the year 2010 is expected to be comprised of SULEVs and ultra-low-emission vehicles (ULEVs). This time period is appropriate for the evaluation of fuel-cycle emissions since a significant fraction of these vehicles may be alternative-fueled or powered by hybrid electric drivetrains.

Assumptions were made regarding which technologies represent current and future fuel production. Scenario 1 represents the current situation (1996 to 2000) and Scenarios 2 and 3 represent a range of emission estimates for the year 2010. The assumptions for each scenario correspond to parameters discussed in Section 3. Advanced vehicle fueling systems that minimize refueling emissions were assumed for vehicles that meet SULEV requirements. The project focuses on fuels that are close to meeting the SULEV standards. Refueling emissions are also calculated.

This study follows the approach used by other studies (Unnasch 1989 and 1996, Wang 1999, DeLucchi and Balles). Emissions are estimated for steps in the fuel production and distribution process. This study relies on both process-specific analyses, using emission factors for fuel-cycle steps, and emission inventories or aggregate data. The report is organized along the modular approach that was used to calculate emissions.

Other than combustion and fugitive emissions associated with fuel production and distribution and vehicle CO_2 emissions, no other environmental impacts are considered in this report. In order to consider the total emissions from fuel production and distribution, exhaust and evaporative emissions need to be added to the fuel-cycle emissions in this study. Only emissions from fuel production equipment are considered in this study. Emissions associated with the production of equipment, facilities, or vehicles have not been included in this report. Spills and upsets are only considered when they are part of routine operations. For example, the probability-weighted emissions from fuel tanker shipment spills are not considered, but average emissions from vehicle fueling spills are counted.

1.5 Report Organization

Section 2 outlines the basic assumptions regarding fuel compositions and fuel properties used in the study. It also discusses NMOG speciation data for fuel, fuel vapor, and exhaust emission. Section 3 presents an overview of the fuel production scenarios for each fuel. The geographical areas where fuels are produced and distributed are identified so transportation and distribution emissions can be accounted for. Section 4 presents emission rates for equipment that is used in the production and distribution of fuels. A data base approach was used to relate the mix of equipment, storage, and transportation modes in Section 3 with emission rates in Section 4. Section 5 discusses the trends in vehicle fuel economy and the likely fuel economy for diesel, LPG, and methanol fuel cell vehicles. Section 6 details the fuel-cycle calculation procedure. The results per unit of fuel produced, as well as a final series of calculations that relates vehicle fuel economy with emissions per unit of fuel determines fuel-cycle emissions on a gram per mile basis. Section 7 describes conclusions related to California air quality policies.

2. Fuel and Feedstock Properties and Compositions

The fuels and feedstocks properties and compositions affect their fuel-cycle emissions. This report accounts for the effect of fuel composition on processing requirements and efficiency, evaporative and fugitive emissions, and combustion emissions. These fuel and feedstock properties and compositions are summarized in this section. The relevant properties include vapor pressure, liquid density, vapor molecular weight, carbon content, and heating value. Each fuel and feedstock is discussed in the following sections. Table 2-1 summarizes the energy and carbon content of the various fuels discussed throughout this report. A range of properties corresponds to most of the fuels and feedstocks in Table 2-1. The values in the table are representative of average compositions. Methanol, ethanol, MTBE, hydrogen, CH_4, and CO are pure compounds with invariant compositions. Feedstocks such as coal, crude oil, and biomass have a wide range in carbon content and heating value. Not all of these fuels are evaluated in this report; however, they are components of the fuel cycle. For coal and crude oil, the range in the ratio of carbon content to energy content is relatively small (Schmidt 1969).

Table 2-1: Energy and Carbon Content of Fuels

	Carbon Content		Energy Content				
Fuel	**C (wt %)**	**C (lb/gal)**	**HHV[a] (Btu/lb)**	**HHV (Btu/gal)**	**LHV[b] (Btu/lb)**	**LHV (Btu/gal)**	**Density (lb/gal)**
Diesel, alternate formulation	86.7	6.24	20,010	139,680	18,300	130,800	7.13
Low aromatics diesel	85.9	5.92	19,560	137,990	18,750	129,350	6.89
Reformulated diesel[c]	86.3	6.06	18,600	137,500	18,360	128,900	7.02
FTD diesel	86.0	5.53	19,900	128,500	18,480	118,800	6.43
LPG from petroleum	82.0	3.44	21,570	90,600	19,770	83,200	4.20
LPG from natural gas	81.8	3.42	21,570	90,160	19,770	82,600	4.18
Methanol	37.5	2.48	9,800	64,800	8,600	57,000	6.6
Hydrogen	0.0	0	61,100	32,400[e]	51,600	27,400[e]	0.53[e]
Conventional gasoline	84.6	5.08	20,800	124,600	19,200	115,400	6.0
Phase 2 RFG	82.8	4.97	20,300	122,000	18,800	113,000	6.0
Additive							
MTBE[f]	68.1	4.22	16,300	100,900	15,100	93,500	6.2
Feedstock							
Crude oil	84.5	6.51	19,100	147,800	17,730	136,500	7.7
Residual oil	90.0	7.29	18,300	148,200	17,700	143,800	8.1
Coal, dry	84.6	—	13,500	—	12,900	—	—
Natural gas[d]	73.6	3.38[e]	22,500	103,000[e]	20,300	92,800[e]	4.59[e]
CH_4	75.0	3.15[e]	23,900	101,200[g]	21,500	91,100[g]	4.2[g]
CO	42.9	3.22[e]	4,300	32,400[g]	4,346	32,400[g]	7.5[g]
Landfill gas	35.6	2.62[e]	6,570	48,300	5,900	43,500	7.4
Biomass, dry	52	—	8,700	—	8,200	—	—
Carbon	100	15.3	14,087	215,000	14,087	215,000	15.3

[a]HHV = Higher heating value.
[b]LHV = Lower heating value.
[c]Diesel with 20 ppm sulfur.
[d]Natural gas distributed in California.
[e]Per 100 scf.
[f]MTBE = Methyl tertiary butyl ether ($CH_3OC_4H_9$).
[g]MathPro 1999, Case 8 HHV and density reported other values estimated.

Source: Acurex 1996, Wang 1999, MathPro 1999.

Carbon content as weight percent, or per MMBtu, is used to determine CO_2 emissions from fuel combustion. Higher heating values are used to relate fuel use to energy consumption for process efficiency calculations, while lower heating values are used to compare vehicle fuel consumption. All calculations can be tracked to a real mass balance, so using higher heating value efficiencies for stationary systems does not create an inconsistency. The molecular weight of fuels corresponds to vapor density and associated evaporative emissions. The values in Table 2-1 were used throughout the report. A calculation of total fuel cycle energy is also performed. For this calculation, all energy is tracked on a lower heating value basis.

2.1 Fuel Composition and Properties

Fuel composition and properties affect many aspects of the fuel-cycle analysis. Liquid fuel and vapor composition and properties are necessary to predict emissions from fuel transfer operations. The vapor pressure of fuels affects the mass emissions from vapor transfers. The composition of fuels affects the mix of toxic compounds from liquid spills as well as that of vapor emissions. Fuel specifications affect refinery energy requirements and to some extent emissions. Finally, the composition of fuels needs to be consistent with values used for energy content, vapor pressure, and vehicle fuel economy.

The following sections summarize the physical properties of the fuels considered in this study. Since the fuels in this study can be represented by a variety of formulations, presenting the potential range in fuel properties provides some insight into how the results of this study might be affected by different fuel properties.

2.1.1 Diesel

Diesel fuel is used to fuel compression-ignited light-and heavy-duty engines. The popularity of diesel as a fuel for passenger cars has dropped in recent years, while diesel is the dominant fuel for trucks. Unlike gasoline, diesel has a low vapor pressure and a low octane number. High quality diesel is characterized by a high cetane number. The ARB implemented a specification for clean diesel that took place in October 1993. This fuel required lower sulfur and aromatics (0.05 and 10 percent maximum, respectively) with an option to meet an alternative specification that results in equal emission benefits. Much of the diesel fuel sold in California after 1993 met alternative specifications that achieved the same emission reductions as the 10 percent aromatics formulation. Table 2-2 shows the heating value, density, sulfur content, and cetane index for various formulations. The low aromatics and alternative formulations were sold in California in 1994.

Table 2-2: Diesel Fuel Properties

Fuel	RVP[a] (psi)	Aromatics (wt %)	Sulfur (ppm wt)	Cetane Index	API Gravity
Low aromatics diesel[b]	0.03	8.3	60	50	39.7
Diesel, alternate formulation[b]	0.03	27.8	250	55.3	33.8
Very low sulfur diesel (RFD)[c]	0.03	30.5	20	47.8	36.5
150 ppm diesel[d]	0.03	30.5	150	47.4	36.2
FT diesel	0.03	0.0	0.0	75	45

[a]RVP = Reid vapor pressure (EPA 2000).
[b]Samples from fuel sold in California in 1994, Unnasch 1994.
[c]Properties from MathPro Case 8.
[d]Properties from MathPro Case 9a.

MathPro evaluated several diesel formulations for the Engine Manufacturers Association (EMA). This analysis included a range of sulfur levels for on-road, off-road, and light-duty diesel fuel. The very low sulfur diesel formulation (20-ppm sulfur) was selected to represent reformulated diesel in California. The properties of other diesel formulations included in the EM study are also shown.

The properties of diesel fuel for this study are shown in Table 2-2. RVP values for diesel are not frequently measured. EPA's document on emission factors from stationary sources (EPA AP-42) shows true vapor pressures for diesel fuel as a function of fuel temperature. The heating value and density of the very low sulfur and low aromatics formulation are consistent with higher hydrogen content in the fuel (shown in Table 2-1).

2.1.2 Synthetic Diesel

Synthetic diesel is being produced from variations of the Fisher Tropsch (FT) process that was developed in the 1920s. FT diesel is a superior fuel for compression ignition engines. It contains virtually no sulfur or aromatics. Its cetane number is 75 compared to 50 for high quality diesel fuels. Both sulfur and aromatics are related to particulate production in diesel engines, while a high cetane number generally results in lower NO_x emissions.

The volumetric heating value of FT diesel is slightly lower than that of conventional diesel fuel since it has higher hydrogen to carbon ratio. Similarly, it has a higher energy content than conventional diesel fuels on a Btu/lb basis. The fuel is colorless and odorless and miscible with conventional diesel fuels.

South Africa and Russia have been operating coal based FT plants since the 1950s. Typical units produce 5,000 to 13,000 bbl/day of synthetic fuel and provide a substantial portion of South Africa's fuel.

More recently, major oil companies have been constructing FT plants that operate on remote natural gas. Shell Malaysia completed at 10,000 bbl/day plant that produces middle distillates and paraffins in 1994. In 1997, ARCO announced plans to build a small-scale gas to liquids plant on the West Coast of the United States. Exxon Mobil is expected to site a 100,000 bbl/day plant in Qatar (Weeden). Chevron/Sasol plans to bring a 33,000 bbl/day facility in Nigeria on line by 2005. Plants operating on both remote natural gas as well as North American gas are possible. An FT diesel plant in Alaska could produce fuels that could be sent to market down the 800-mile trans-Alaska pipeline. The production of such fuels could make up for declining oil production. In 1997, Tosco and Paramount Petroleum also blended Shell's FT diesel to produce clean diesel for sale in California.

2.1.3 LPG

The composition of LPG represents typical analyses of fuel collected in Southern California (Unnasch 1994). Propane and butanes produced in oil refineries are now mostly converted to alkylate, used in the production of ethers, or sold into the chemical market; however, this LPG could be diverted to a higher value fuel market. Petroleum-based LPG contains several percent propylene, while natural gas based LPG contains no propylene or other olefins. The zero olefin composition of natural gas derived LPG is consistent with the feedstock LPG compositions from petroleum and natural gas are shown in Table 2-3.

Table 2-3: Composition and Properties of LPG

Property	LPG[a] from Petroleum		LPG from Natural Gas	
Carbon (wt %)	82.0		81.8	
LHV[b] (Btu/lb)	19,770		19,770	
(Btu/gal	83,200		82,600	
Density (lb/gal)	4.21		4.18	
Composition	**(vol %)**	**(wt %)**	**(vol %)**	**(wt %)**
N_2	0	0	0	0
CO_2	0	0.0	0	0
CH_4	0.05	0.03	0.1	0.06
C_2H_6	0.5	0.37	2.0	1.48
C_3H_8	94.15	93.9	97.0	97.5
C_3H_6	2.3	2.3	0	0
C_4H_{10}	3.0	3.4	0.9	1.0
C_5H_{12}	0	0	0	0

[a]LPG = Liquefied petroleum gas.
[b]LHV = Lower heating value.
[c]per 100 scf.

Source: Unnasch 1994.

The propylene (C_3H_6) content of the LPG samples in Table 2-3 indicates that one sample was largely from petroleum-derived sources and another sample was derived from natural gas. Discussions with representatives of the LPG industry indicated that these fuel compositions are consistent with LPG distribution practices in California. No LPG is distributed by pipeline for vehicle use in Southern California. Refinery based LPG and natural gas based LPG are both hauled by railcar and truck and stored at central distribution facilities. In come instances the product is not co-mingled, which is reflected in the product composition. The majority of this sample came from an oil refinery. ARB's specification limits propylene to a maximum of 5 percent; however, observations of propylene in commercial LPG have shown lower levels. LPG is stored in pressure vessels. At 100°F the vapor pressure is about 190 psi.

2.1.4 M100

The composition of M100 is 100 percent methanol. The composition of fuel vapors is the same as that of the liquid. M100 contains trace contaminants of water and hydrocarbons (Table 2-4). However, fuel cell vehicles with methanol stream reformers will likely not be able to operate effectively with percent levels of hydrocarbons. Therefore, hydrocarbon free fuel was assumed. Hydrocarbon levels in the ppm range would not affect steam refiners and these levels would have an insignificant impact on fuel-cycle emissions. Measurements of M100 contaminants from vehicle demonstration programs indicate negligible hydrocarbons and typically less than 1000-ppm water. The effect of this level of water on vapor pressure and heating value is negligible.

Table 2-4: Properties of Methanol Fuels[a]

Component	RVP[b] (psi)	Composition
Methanol	4.63	>99.85%
Hydrocarbons [c]	—	<1,000 ppm
Water[c]	—	<5,000 ppm

[a]M100 = 100 percent (neat) methanol.
[b]RVP = Reid vapor pressure.
[c]Hydrocarbon and water level assumed for the purpose of determining fuel-cycle emissions. Lower levels may be required for fuel cell vehicle operation.

2.2 Feedstocks

2.2.1 Crude Oil

Crude oil contains a mixture of hydrocarbons with a range of compositions and is characterized by its API gravity that is inversely proportional to specific gravity. This property determines how "heavy" the oil is and relates to its carbon content and heating value. The properties of typical crude oil are shown in Table 2-1.

2.2.2 Natural Gas

Table 2-5 shows the properties of gaseous fuels. The natural gas compositions are an average of measurements provided by SoCalGas for gas delivered in Southern California. These values resemble closely the weighted average of natural gas composition for ten U.S. cities reported by GRI[4] (Liss). While some natural gas supplies can vary significantly in composition, 80 percent (10th through 90th percentiles) of natural gas reported by GRI had a methane content within 88.5 to 96.4 percent. All gas that is currently sold in California is reported to have a relatively high methane content with typical methane contents above 92 percent, which is within ARB's vehicle fuel specification of 88 percent (vol).

Table 2-5: Composition and Properties of Gaseous Fuels

Property	Digester Gas		Landfill Gas		Pipeline Natural Gas	
Carbon (wt %)	44.5		35.9		73.6	
LHV[a] (Btu/lb)	7,910		6,350		20,300	
(Btu/100 scf)	5,550		45,300		92,800[c]	
Density (lb/100 scf)	7.02		7.1		4.6[c]	
Composition	**(vol %)**	**(wt %)**	**(vol %)**	**(wt %)**	**(vol %)**	**(wt %)**
N_2	1.1	1.2	16	16.5	1.6	2.6
CO_2	37.6	62.1	31	50.4	1.0	2.5
CH_4	61.3	36.8	50	29.5	93.2	86.4
C_2H_6	0	0	0	0	3.1	5.4
C_3H_8	0	0	0	0	0.7	1.8
C_3H_6	0	0	0	0	0	0
C_4H_{10}	0	0	0	0	0.4	1.3
C_5H_{12}	0	0	0	0	0	0
O_2	0	0	3	3.5		

[a]LHV = Lower heating value.

Source: Arthur D. Little.

As natural gas demand increases to meet vehicle requirements, California will need to import more natural gas. This gas will probably be supplied from Canadian and Southwest U.S. sources (Thomason).[5] Canadian gas has higher methane content because hydrocarbons are extracted for LPG use. An average of 50 percent Canadian gas and 50 percent Southwest gas results in a mixture that is very close to the value in Table 2-3. Since the exact mix of incremental gas for vehicle fuel is difficult to predict,

[4] Mean composition (vol%) for ten cities in the U.S. was methane: 93.2, ethane: 3.6, propane: 0.8, >C_4: 0.5, inerts 2.8.

[5] Canadian gas composition (vol%) methane: 96.99, NMHC: 1.46. Southwestern gas composition (vol%) methane: 91.48, NMHC 6.33). Shortages of natural gas may require new sources such as LNG from Mexico or new gas sources in Alaska.

and the composition in Table 2-3 is also representative of U.S. gas as well as possible new gas supplies to California, this composition is used throughout the study. The compositions in Table 2-3 are also shown as weight percent values, so they can be treated consistently with liquid fuel compositions and to allow for calculation of ozone potential on a mass basis. Natural gas that is used for methanol production in remote locations would not have as many hydrocarbons or CO_2 removed as pipeline gas in the U.S. (Allard). The higher CO_2 content would lead to a slightly higher methanol yield as discussed in Section 4.

2.2.3 Landfill Gas and Digester Gas

Landfill gas is produced when organic material decomposes in a landfill. The organic material converts to methane and CO_2 through biological decomposition. Traces of sulfur containing compounds and chlorinated compounds occur in landfill gas. Air can also be entrained in landfill gas. When landfill gas is removed from the center of a landfill, the gas has a higher methane and CO_2 content. Gas that is extracted from the periphery of a landfill contains more nitrogen and some oxygen. Table 2-5 shows the compositions of landfill gas and digester gas which are potential feedstocks for methanol production. Data from a digester included speciations of hydrocarbons that determined that non-methane hydrocarbons were below 0.1 percent by volume.

Landfill gas and digester gas represent limited resources for fuel production. Many sewage treatment plants and landfills burn landfill gas to produce electric power. However, some facilities still flare landfill gas. Landfill gas is a relatively cost effective feedstock although it represents a small fraction of the total potential methanol market.

2.2.4 Biomass

Lumbermill waste and forest thinnings were considered for plants operating on forest material. Removing biomass from forests that have a high risk of fire is a source of feedstock for electric power generation and planned ethanol production. The benefits of harvesting forest thinnings also include increasing water available for larger trees, reduced fire fighting costs, and potentially reducing insect damage (Perez).

Providing a steady amount of forest material year round is not always possible as environmental constraints limit timber harvesting to non-rainy months. The amount of forest material that could be available in proximity to a potential methanol plant limits the plant size to about 40 million gallons per year. This plant size is relatively small for a capital-intensive methanol facility. A mixture of urban waste and agricultural waste was assumed necessary to provide a plant size over 100 million gallons per year. Urban wood waste and tree trimmings could provide additional biomass feedstocks for methanol production. Sewage sludge has also been considered a feedstock for gasification (Steinberg).

Wood waste, tree trimmings, and yard waste are separated in many areas. Competing uses for the highest quality of urban wood waste would require blending with lower value feedstocks, such as tree prunings, to reduce feedstock costs. Most urban wood waste that is currently burned in biomass power plants consists of larger branches from tree pruning and removal with very little clean wood residue from furniture and lumber operations. Urban wood waste is a limited resource for existing biomass power plants, and, if used as a methanol feedstock, the price and transportation distance would increase. Chipped tree branches and yard waste are other potential feedstocks. These materials are either composted or used for landfill cover and are not suitable as fuels for biomass power plants. Sorting and quality control steps may need to be taken with branches and yard waste, as these can quickly rot, may contain unexpected contaminants, and can have a high ash content.

Energy crops could provide additional feedstocks for methanol production. Eucalyptus was assumed as a potential energy crop since it has low water requirements and could be grown in many parts of California. It also could be used in areas where ground water contamination may be mitigated by planting trees. Energy crops are considered to be more costly feedstocks than waste biomass. Table 2-6 shows the composition of some biomass materials.

Table 2-6: Composition of Biomass Materials

	Pine		Eucalyptus		Poplar	
Component	**Wet**	**Dry**	**Wet**	**Dry**	**Wet**	**Dry**
Moisture	57.06	—	40.4	—	5.6	—
Carbon	23.16	53.93	30.59	51.32	47.05	49.84
Hydrogen	2.68	6.23	3.67	6.16	5.73	6.07
Nitrogen	0.85	1.97	0.7	1.18	0.41	0.43
Sulfur	0.13	0.31	0.08	0.13	0.05	0.05
Ash	1.46	3.41	3.96	6.64	0.47	0.5
Oxygen	14.66	34.15	20.6	34.57	40.69	43.11
Total (wt %)	100	100	100	100	100	100
HHV (Btu/lb)	3,996	9,306	5,265	8,834	7,421	7,861

Source: A. D. Little.

2.3 Electric and Steam Energy

Electrical energy in this study is reported in electric kWh. Thermal energy used in generating electricity and other fuels is reported in Btu. With this approach, electrical energy and thermal energy should not be confused. Converting electrical energy to thermal energy incorporates the efficiency of the power conversion process. For example, if a diesel engine generator set operates with an efficiency of 34.1 percent (HHV), 10,000 Btu are required to produce 1 kWh.

Both electric power and steam can be inputs and outputs for fuel production processes. When power or steam is exported from a fuel production facility, energy is displaced from another facility. Exports of power and steam result in a reduction in energy use and emissions and are counted as a credit in this study. The quantification of credits is shown in Table 2-7. Generating power in California is estimated to displace relatively efficient combined cycle power plants. In remote locations, a less efficient combined cycle power plant was assumed where the price of natural gas is lower. A credit for cogenerating steam reflects the displacement of energy from a natural gas fired boiler. The energy requirements to generate electric power generation depend on many factors and are discussed later in this report. The energy credits shown in Table 2-7 are within the range of estimates presented in other studies (Wang 1999). These values have little impact on the results for methanol, FT diesel, diesel, or LPG.

Table 2-7: Energy Credits for Power and Steam

Primary Energy	Location	Energy Displaced (HHV)	CO_2 Displaced
1 kWh electricity	Remote Location	10,000 Btu [a]	600g
10,000 Btu steam	Remote Location	12,500 Btu [a]	754g
1 kWh electricity	California	9,000 Btu [b]	540g

[a] Natural gas.
[b] Composite combustion generation in California.

3. Definition of Fuel Cycles

This study considers fuel-cycle emissions from vehicle fuels. The analysis considers the marginal, or incremental gallon (or equivalent fuel unit), consumed in the SoCAB. The volumes of fuel in this study are consistent with vehicles that might qualify as PZEVs under the ARB's LEV program.

Three example scenarios were developed to cover the range in emissions due to fuel-cycle assumptions. Many of these fuels can be produced from several feedstocks. Table 3-1 shows the fuel/feedstock combinations considered in this study. The codes that correspond to the fuels and feedstocks are used later to identify emission rates in a database. The combination of feedstocks and fuels represents a specific combination of production technologies and feedstocks. For example, methanol from natural gas is considered separately from methanol from biomass, while a combination of feedstocks is considered for electricity production. While a variety of feedstocks contribute to power production, natural gas is likely to be the fuel used on the margin as discussed in Section 4.8.

Table 3-1: Feedstock/Fuel Combinations Considered in This Study

Feedstock	Code[a]	Fuel	Code	Vehicle[b]
Crude oil	o	Diesel	D	CI IC
Crude oil	o	RFD	RD	CI IC
Crude oil	o	LPG	P	SI IC
Natural gas	n	Synthetic diesel	F	CI IC
Natural gas	n	LPG	P	SI IC
Natural gas	n	Methanol	M	Steam reformer PEMFC
Landfill gas	l	Methanol	M	Steam reformer PEMFC
Biomass	b	Methanol	M	Steam reformer PEMFC
Various	x	Electricity	J	Battery only EV

[a]Codes refer to feedstock and fuel designations used in database.
[b]CI IC = compression ignition internal combustion engine, SI CI = spark ignited internal combustion engine, PEMFC = proton exchange membrane fuel cell, EV = electric vehicle.

The fuel-cycle emissions in this study are represented as the weighted average of different production and distribution technologies described in this section. Some fuel/feedstock combinations, such as methanol from natural gas, were represented separately while others were combined to simplify the comparison of fuels in Section 7. The basis for scenarios, mix of feedstocks, as well as production and distribution technologies is described below.

3.1 Scenarios

Scenario 1 represents the fuel cycle emissions from fuel production activities that occurred in the 1996 to 2000 timeframe. This scenario represents current emission regulations. Hypothetical vehicles and fuel demand is assumed to provide a basis of comparison with Scenarios 2 and 3. Scenario 3 represents a base case where regulations for refueling emissions are consistent with requirements for gasoline fueled vehicles. Furthermore, higher range of assumptions that affect emissions are considered in Scenario 2. The assumptions in this scenario are still consistent with emission regulations but reflect an interpretation with higher emission level.

3.2 Information Organization

Identifying emissions by spatial location complicates the analysis of fuel-cycle emissions considerably, since fuel and feedstock transportation distributes emissions in several of the geographic locations considered in the study. Therefore, the information for this project is organized into a database that calculates spatial emissions and combines these results with vehicle fuel economy to represent fuel-cycle emissions on a g/mi basis. The information is in three databases that include the following information:

- Production and distribution emission rates
- Emission weighting and spatial distribution
- Vehicle fuel economy

Assumptions for emission scenarios, geographic distribution, production and distribution for the fuel/feedstock combinations, and production and distribution technology mixes are discussed below. Further information on the specific mix of technologies and energy use parameters is provided in Section 4. These databases are included in Volume 2. Since marginal emissions in the SoCAB represent a limited set of emissions sources, all of these sources are presented in Section 6.

3.2.1 Fuel Production Phases

These steps are categorized into eight production and distribution phases, shown in Table 3-2. These phases are grouped into the categories extraction, production, marketing, and distribution, which are later used for presenting the combined emissions in Section 6.

3.2.2 Geographic Distribution

Because some fuels will be produced outside of California, emissions from the entire fuel-cycle will not directly impact California urban areas. For this reason, it is important to identify the percentage of feedstock extracted or fuel produced in each area. In order to help evaluate the impact on local emission inventories and air quality as well as to take into consideration the differences between local emission rules, the emissions were geographically categorized. Emissions from fuel production can then be allocated according to the locations in Table 3-3. This table also shows the acronyms used to identify each of these areas for this report.

Table 3-2: Fuel-Cycle Emissions were Categorized into Eight Production and Distribution Phases

Phase No.	Description
Extraction	
1.	Feedstock extraction
2.	Feedstock transportation
Production	
3.	Fuel processing/refining
Marketing	
4.	Fuel storage at processing site
5.	Transport to bulk storage
6.	Bulk storage
7.	Transport to local distribution station
Distribution	
8.	Local station distribution

Table 3-3: Locations of Emissions

Location	Acronym
Within the SoCAB	SC
Within California, but outside the SoCAB	CA
Within the U.S., but outside of California	U.S.
Rest of the World, outside the U.S.	ROW

Emissions for fuel or feedstock transportation and distribution are also divided into the four geographic distribution categories. For example, emissions for ships entering and exiting the San Pedro ports were attributed to the SoCAB for a portion of the trip. The balance of these emissions was attributed to the rest of the world. Both land and sea transport emissions were allocated proportionally according to their transport route.

This study is intended to be used to evaluate marginal emissions from fuel production. Information is also provided to determine average emissions. The interpretation of which emissions correspond to marginal fuel production depends on several factors that are discussed in the following section. The focus on marginal emissions raises questions of transporting emissions into and out of the state. For example, methanol could be sold for vehicle use in the SoCAB without any production emissions affecting local air quality. Similarly, gasoline is transported to other states from the SoCAB, while the refinery emissions contribute to emission inventories in the SoCAB.

3.3 Marginal Emissions

This study pays considerable attention to the marginal fuel-cycle emissions. Many industry stakeholders participated in the 1996 Acurex study (Unnasch 1996). During the course of projects meetings, it was clear that the subject of marginal emissions was important to the stakeholders. When the subject of fuel-cycle emissions becomes meaningful in a regulatory or economic sense, stakeholders become acutely interested in the outcome of such an analysis. Since marginal emissions would represent the impact on air quality from using additional fuel, these emissions are of interest from a policy point of view. Industry stakeholders in 1996 strongly urged that fuel cycle emission studies be based on a marginal analysis.[6]

Marginal emissions are affected by local air quality regulations, permit requirements for new facilities, permits for existing power generation capacity, the source of feedstocks, and economic forces. Ideally, a fuel-cycle analysis would reflect the interaction of regulatory, economic, and supply considerations. An important parameter is the total volume of fuel that is sold. When evaluating the effect of using an alternative fuel, the implicit assumption is that the alternative displaces gasoline. However, if alternative fuels captured market share, through economic or regulatory forces, additional gasoline would be available for sale. The effect of alternative fuel use in California could achieve the following effects:

- Displace gasoline sales
- Provide additional gasoline which could reduce the price of gasoline and stimulate demand
- Increase the supply of oil and put downward pressure on oil prices

Such price-elasticity issues have a more significant effect on global fuel production. In California, fuel demand is fairly inelastic and stationary emissions are largely driven by regulatory considerations. For the vehicles and fuels considered in this study, fuel demand would represent modest volumes in relation to total gasoline and diesel consumption in California. A very high passenger car demand for diesel, methanol, LPG, or electric power, would at most be 200 million gallons (gasoline equivalent) per year in 2010 while total gasoline demand would be 15 million gallons per year. Even if alternative fuel demand were 1 billion gallons per year (gasoline equivalent), there would be little difference in emissions from refineries in California.[7]

Emissions for marginal alternative fuel production and gasoline displacement were calculated for fuel-cycle activities in the SoCAB. The marginal emission values were determined according to Table 3-4. The net result of the marginal analysis is that NO_x emissions amount only to tanker ship and truck emissions in the SoCAB. All other NO_x

[6] The emphasis on marginal emissions by industry groups was a key outcome of the 1996 study. Industry groups and State agencies ultimately agreed that a marginal approach was relevant in the context of a moderate usage of alternative fuels. The alternative point of view is that a very substantial use of alternative fuels could result in a reduction in refinery capacity. Given the limited refinery capacity and growth in gasoline demand, this outcome is unforeseen.

[7] See discussion of petroleum fuels in the following section. This conclusion implies that marginal refinery emissions from diesel and LPG production would be zero. The emission impact of displacing a very large fraction of refinery capacity with alternative fuels is not analyzed here. Even if such a scenario were to occur, it is uncertain that average emission rates would accurately reflect the impact on emissions as the disposition of emission permits and offsets would need to be taken into account.

emissions are either controlled by RECLAIM or are associated with fuel production out side of the SoCAB. NMOG emissions correspond to fuel storage and distribution activities as well as power production for EVs. For greenhouse gas pollutants, particularly CO_2, the marginal analysis is less critical for diesel, LPG, FTD, and methanol production. As discussed in Section 4.8, the mix of power generation sources on the margin is, however, important for determine efficiency and CO_2 emissions related to EV operation. In the following discussion, the fuel production phases are summarized in a table for each fuel. Marginal emission sources are identified for each fuel.

Table 3-4: Adjustments for Marginal Fuel-Cycle Emission Analysis in the SoCAB, 2010

Fuel	Marginal Analysis Assumptions
Diesel	Zero emissions for crude oil production and refinery.
Reformulated diesel, LPG	Same as diesel. Add emissions associated with additional refinery energy use (electric power and natural gas).
Methanol from natural gas, biomass, FTD	Produced outside of the South Coast. Feedstock extraction and refinery do not result in SoCAB emissions.
Methanol from LFG	Credit for reducing NMOG emissions from flaring.
Natural gas for refineries	Zero emissions except for pipeline transmission emissions. Emissions associated with pipeline leakage do not increase with increased throughput.
EV, power for refineries	Marginal power from natural gas. NO_x would be zero for electric power generation.

Some environmental groups and researchers consider the marginal analysis in this study to provide optimistic results. Indeed, the marginal emissions are lower than average emissions. However, both electric and liquid fueled technologies are being compared on a marginal basis. In the author's view, marginal emissions represent the contribution to the air that the breathers breathe. Only substantial changes in the environmental and economic structure of fuels would result in emissions equal to the average emissions from refineries. For example, if new refineries were to be built in California or capacity were increased beyond currently permitted levels, the contribution to air emissions on the margin would need to be reexamined. In principle, new petroleum refineries could be constructed in California and emission offsets could be obtained. The use of new fuels, such as reformulated diesel, for PZEV vehicles in California would not trigger such infrastructure changes.

3.4 Petroleum Fuels

Diesel and LPG are produced from crude oil. These fuels, along with gasoline and other refinery products, share the same crude oil feedstock and therefore the same extraction and feedstock distribution paths (LPG, however, can also be produced from natural gas).

Table 3-5 summarizes the eight phases for conversion of crude oil to diesel and reformulated diesel.

Table 3-5: Diesel Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NO$_x$	Marginal Emissions[a] NMOG
1	Extraction	Heaters, pumps, fugitive	—	—
2	Transport	Pipeline (pumps), ships (engines), fixed roof storage tanks	M	M
3	Refining	Fugitive emissions, refinery heaters	—	M
4	Site storage	Refinery tanks	0	M
5	Transport to bulk storage	Pipeline (pumps & fugitive)	M	—
6	Bulk storage	Floating roof diesel tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Underground tanks, refueling vapors, spills	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

3.4.1 Crude Oil Extraction

Crude oil for refineries in the SoCAB is produced from offshore and underground wells in the southern coast and San Joaquin Valley. Heavy crude from Kern County represents a large share of this product. Oil is also imported by tanker from Alaska and overseas. Table 3-6 shows the assumptions used for geographically allocating emissions to petroleum extraction and transport.

Table 3-6: Petroleum Extraction for SoCAB Use

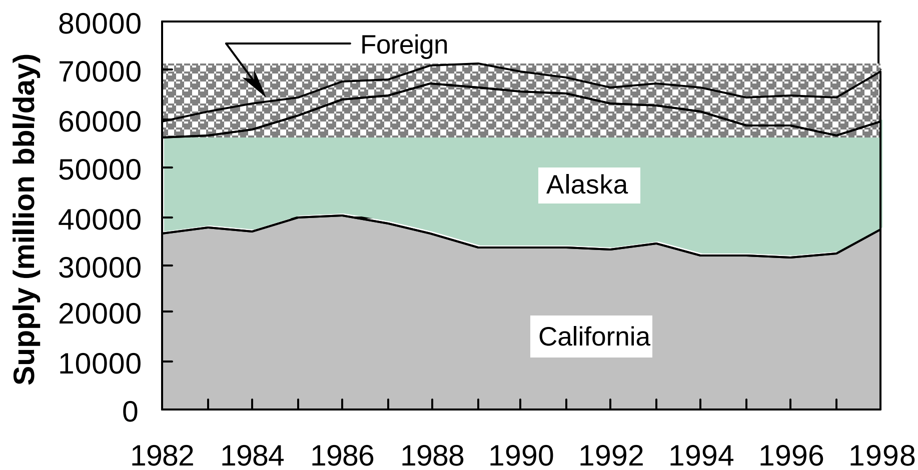
Feedstock Location	% of Volume
Average[a]	
South Coast (SC)	9
California (CA)	44
Alaska (U.S.)	32
ROW	15
Marginal	
ROW	100

[a] Crude oil sources for 1998. These crude imports represent the average. Marginal petroleum production comes from imports.

Source: CEC

California processes about 1.8 million barrels of crude oil per day. In 1990, 48 percent of this oil was produced in California; 46 percent was imported from Alaska; and the remaining 6 percent was imported from foreign sources. These values dropped to 32 percent from Alaska in 1998, with California supply increasing to 53 percent and foreign supplies growing to 15 percent. Crude oil in California is primarily a heavy variety that is extracted by steam injection. New oil sources in the state are limited and prospects for new offshore production are unlikely. California's imports of foreign crude oil have not been large because several refineries have been modified to run efficiently on Alaska North Slope oil. CEC projects increased competition for Alaskan oil with an increase in demand in the western U.S. (PADD V) and declining Alaskan production (CEC April 2001c). Allocation of crude oil production and refinery emissions to the SoCAB depends on whether an incremental gallon of gasoline or the average gallon of gasoline is considered. Figure 3-1indicates the trend in increased imports of foreign oil and declining Alaskan production for California refineries.

Figure 3-1: Oil supply sources for California Refineries



Source: CEC.

Significant fraction of crude oil is produced in the SoCAB, and marginal emissions associated with oil production in the SoCAB are estimated to be near zero. Refineries in the SoCAB operate at capacity, and demand for additional diesel could be met by importing additional finished diesel fuel. Oil production is estimated to not change with additional demand for diesel fuel, as additional product may be imported to California or refinery operations may be modified slightly to produce more diesel and less gasoline.

This assumption does not suggest that the mix of California to imported oil should remain invariant under all conditions, merely that moderate changes in fuel demand will not shift the mix of crude oil sources. The mix of crude oil could change with changing oil prices. If oil prices dropped substantially, for example, more costly oil production in California could be reduced. Crude oil production techniques depend on the demand for oil. Increased use of more energy intensive techniques such as enhanced oil recovery would correspond to higher petroleum prices. The trend in California is to extract more oil through thermally enhanced oil recovery (TEOR). This report does not attempt to predict a change in oil feedstocks or changes in production techniques over the scenarios in this study.

3.4.2 Crude Oil Transport

Oil is transported to the refineries using two primary methods: pipelines and tanker ships. Pipeline emissions result from the pumps that move the oil through the pipelines. Tanker ship emissions are produced by the propulsion and auxiliary engines, which operate on heavy fuel oil. Table 3-7 shows the estimated mix of crude oil and finished petroleum product imports to California. This mix of locations would represent the average oil production mix for California. However, as discussed previously, an increase in diesel demand due to additional diesel consumption related to fuel switching (rather than a drop in prices) is estimated to result in no change in oil import emissions. While crude oil is imported from a variety of sources, Singapore was selected as a ROW location to represent transportation distances. Other sources, such as Venezuela, are also remotely located from California.

Table 3-7: Petroleum Transport for Average SoCAB

Transport Process	Location	One Way Distance (mi)
Oil pipeline	South Coast (SC)	20
Oil Tanker	Alaska (U.S.)	1976
	Singapore (ROW)	7,650
Product tanker	Singapore (ROW)	7,650
Marginal		
Product tanker	Singapore (ROW)	7,650

3.4.3 Oil Refining

A variety of fuels are produced by oil refineries in the SoCAB. Products from refineries include several grades of gasoline, diesel, kerosene (jet fuel, heating oil, No. 1 Diesel), LPG, heavy oil, petroleum coke, sulfur, and asphalt. Energy inputs to refineries include crude oil, electric power, natural gas, gasoline blending stocks such as alkylate (high octane components such as iso-octane), and oxygenated compounds such as methanol, MTBE, and ethanol. The specifications for fuel in California have been changing over the years with sulfur reductions in diesel, reformulations of gasoline, low aromatics and equivalent diesel, and reductions in the use of MTBE. At the same time, emissions from refineries in the SoCAB have been declining steadily. The combination of feedstocks, products, and emissions makes allocating emissions to refinery products difficult.

It is unlikely that new refineries will be built in California. In fact, from 1985 to 1995, ten California refineries closed, resulting in a 20 percent reduction in refining capacity. Further refinery closures are expected for small refineries with capacities of less than

50,000 bbl/day. The cost of complying with environmental regulations and low product prices will continue to make it difficult to continue operating older, less efficient refineries.

To comply with federal and state regulations, California refiners have invested approximately 5.8 billion dollars to upgrade their facilities to produce cleaner fuels, including reformulated gasoline and low-sulfur diesel fuel. These upgrades have received permits since low-sulfur diesel fuel regulations went into effect in 1993. Requirements to produce federal reformulated gasoline took effect at the beginning of 1995, and more stringent state requirements for ARB reformulated gasoline went into effect statewide on June 1, 1996.

As a first order estimate, there are no marginal emissions associated with producing more conventional diesel or LPG in a refinery. Several possibilities exist for adjusting refinery operation for changes in fuel output. If gasoline demand were reduced, it is likely that imports of finished gasoline would simply be reduced. Increased diesel demand at the expense of gasoline sales could be met by increasing the mix of diesel products that are imported to the SoCAB or by adjusting refinery operations to produce more diesel. Analyzing the effect of changing the shift in refinery products ideally would be accomplished by a linear programming (LP) model that optimizes all of the refinery streams for an optimal economic and fuel specification output. Such LP analyses primarily are aimed at analyzing the effect of different fuel formulations or refinery process configurations. Published studies are not aimed at trading off LPG or diesel for gasoline.

Emissions from oil production in the SoCAB are expected to decrease over the next 20 years with the following measures:

- NO_x controls on refinery fluid catalytic cracking units
- Emission controls on off shore oil production
- Emission controls from refinery flares
- Carbon absorption, refrigeration, and incineration of fugitive hydrocarbons
- Emissions controls from bulk terminals

3.4.3.1 Diesel

If a significant amount of gasoline output were replaced with diesel, the operation of some energy intensive processes such as reforming and alkylation would be reduced with a net reduction of energy for refining. Such a displacement of emissions would result in the reduction of some refinery heat energy inputs with a reduction in combustion emissions. Total NO_x emissions from refineries would not be affected by a change in combustion emissions, as refinery NO_x is under a cap through the RECLAIM program. NMOG emissions from combustion sources would however be reduced if fuel combustion were reduced due to a reduction in gasoline output and an increase in diesel output. As shown in Section 4.3, combustion NMOG emissions represent a smaller share of NMOG sources within oil refineries than do fugitive NMOG emissions. Variations in throughput have little impact on fugitive emissions.

Producing reformulated diesel would also affect refinery operations. Reformulated diesel will contain less sulfur and may also have a higher cetane index. Removing additional sulfur beyond current levels could be accomplished with severe conventional hydrotreating. The effect of producing reformulated diesel was estimated to be reflected by a change in sulfur from 150 ppm to 20 ppm for on road diesel. MathPro performed an LP model analysis of such a change in diesel fuel formulation (MathPro 1999). The results of the model reflected a change in energy inputs to the refinery that are discussed in Section 4.3. The model shows primarily an increase in electric power demand by the refinery with a small increase in crude oil imports. Emission impacts were estimated to correspond to the generation of power and combustion of additional refinery fuel.

3.4.3.2 LPG

Producing additional LPG was estimated to have zero marginal emission impacts from refineries in the SoCAB. The marginal uses of LPG are selling the product as a fuel or use as a refinery fuel or feedstock. Selling additional LPG for vehicle use would displace LPG sales to other customers and also displace LPG as a refinery fuel where it might be replaced with natural gas. Oil refineries may burn propane if the demand for it as a home heating or vehicle fuel is low. However, higher market prices (demand) would probably divert propane for use as a vehicle fuel (refineries would burn natural gas as a replacement). California imports a significant quantity of LPG. This LPG comes from natural gas processing facilities in Canada and the southwest United States. Some LPG is also imported from refineries in Utah. Future demand for LPG could be so high that marginal demand must come largely from natural gas liquids. However, given the opportunities for displacing LPG from refinery use, and the source of current LPG, this study assumes refinery-based and natural-gas-based LPG production.

3.4.4 Diesel Storage and Distribution

After diesel is produced in a refinery, it is stored in bulk tanks and distributed to fueling stations in tank trucks. Emissions resulting from the storage of petroleum and petroleum fuels consist of two main types: fugitive and spillage emissions. Fugitive emissions are hydrocarbon emissions that escape from storage tanks, pipes, values, and other sources of leaks. These emissions are generally greater for gasoline than diesel, due to its higher vapor pressure.

The low vapor pressure of diesel has generally resulted in limited requirements on vapor recovery from storage and fueling equipment. The vapor pressure from diesel is so much lower than that of gasoline, that the uncontrolled diesel vapor losses are less than 10 percent of gasoline emissions with 95 percent emission control (see Section 4.9).

Vapor losses primarily occur when tank trucks are filled at the bulk terminal, unloaded at the fueling station, and during vehicle fueling. Spillage during vehicle fueling is also a significant source of emissions.

3.4.5 LPG Storage and Distribution

The fuel-cycle steps for LPG parallel those for diesel. LPG is stored and distributed in pressurized tanks, as indicated in Table 3-8.

Table 3-8: LPG from Crude Oil Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NOx	Marginal Emissions[a] NMOG
1	Extraction	Heaters, pumps, fugitive	—	—
2	Transport	Pipeline (pumps), ships (engines)	M	M
3	Refining	Refining process emissions	—	M
4	Site storage	Refinery tanks	0	M
5	Transport to bulk storage	Tanker truck	M	M
6	Bulk storage	Pressurized tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Above ground tanks	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

3.5 LPG from Natural Gas

LPG is produced when liquids are extracted from natural gas. Marginal emissions in the SoCAB are zero since processing of LPG occurs in Canada or the Southwest states. Table 3-9 shows the steps associated with distributing LPG from natural gas. The principal difference affecting marginal fuel cycle emissions is the additional transportation by rail car from outside California.

The emissions rate for fugitive losses was determined from the annual emissions divided by annual production. Based on this data, fugitive losses in the United States represent 0.8 percent of total throughput. Fugitive losses were allocated to natural gas and LPG. The allocation to LPG was 3 percent, which is proportionate to the LPG content in natural gas from the well. Marginal leakage is likely low. Gas sweetening plants produce fugitive losses of heavy glycols. Methanol is used in drying systems for local compressors. The volume of methanol is negligible. Further details of fugitive emissions from LPG production are discussed in Section 4.3.

Table 3-9: LPG from Natural Gas Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NO_x	Marginal Emissions[a] NMOG
1	Extraction	Natural gas wells	—	—
2	Transport	Gas pipelines	—	—
3	Refining	Natural gas processing	—	—
4	Site storage	Pressurized tanks	—	—
5	Transport to bulk storage	Rail car (engines and fugitives)	M	M
6	Bulk storage	Pressurized tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Above ground tanks	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

LPG is shipped in 30,000 gal rail cars. The fuel is transferred to 30,000 storage tanks either by pumping from the rail car or by 10,000 gal tanker trucks. Fuel is delivered to local service stations in 3,000 gal trucks, where it is stored in 1,000 gal tanks. If LPG use for vehicles were to increase, the capacity of local delivery trucks and storage tanks would also increase. For fleets that consume large quantities of LPG, larger storage tanks would be used. Local storage tanks as large as 10,000 gallons have been used for transit fleet operations that also fuel light-duty vehicles. Fugitive emissions from LPG transfer occur when fuel is transferred from to a storage tank as well as rail car, truck, and vehicle tanks (Lowi). When a tank is filled, liquid LPG fills the tank and LPG vapors condense. When a tank is filled, a small amount of LPG vapor is vented as part of the tank filling procedure which is described in Section 4.9.

3.6 Fuels from Remote Natural Gas

Synthetic diesel and other synthetic liquid fuels are formed from a three-step process (known as the Fischer-Tropsch [FT] Process) which converts coal, biomass, or natural gas to liquid fuels. It is an attractive air quality option to conventional fuels because it contains no sulfur or aromatics and has a higher cetane number. This study considers only synthetic diesel from natural gas because it is the most economically attractive option.

As a result of this process, the fuel cycle for synthetic diesel at the upstream end is similar to that of methanol. Table 3-10 shows the steps associated with FT Process production and distribution.

Table 3-10: Synthetic Diesel Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NO$_x$	Marginal Emissions[a] NMOG
1	Extraction	Compressors, fugitive	—	—
2	Transport	Natural gas pipeline (compressors & fugitive)	—	—
3	Conversion	Fugitive emissions, vent gas combustion	—	—
4	Site storage	Fixed roof tanks	—	—
5	Transport to bulk storage	Tanker ships	M	M
6	Bulk storage	Floating roof tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Underground tanks, refueling vapors and spillage	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

Methanol, like synthetic diesel, can be produced from a variety of feedstocks. Most methanol in the world and all of the methanol used in California as a vehicle fuel is made from natural gas. The conversion process typically used, called steam reforming, is similar to the process used to make synthetic diesel, but uses different catalysts, temperatures, and pressures. The upstream fuel cycle is similar to compressed natural gas. Fuel distribution for methanol consists of bulk storage terminals and transfer systems similar to those for gasoline. The steps for methanol production and distribution are shown in Table 3-11.

Table 3-11: Methanol from Natural Gas Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NO$_x$	Marginal Emissions[a] NMOG
1	Extraction	Compressors, fugitive	—	—
2	Transport	Natural gas pipeline (compressors & fugitive)	—	—
3	Production	Fugitive emissions, vent gas combustion	—	—
4	Site storage	Fixed roof tanks	—	—
5	Transport to bulk storage	Pipeline (pumps & fugitive)	M	M
6	Bulk storage	Floating roof tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Underground tanks, refueling vapors and spillage	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.

The following discussion covers the extraction and transport of remote natural gas for Fischer-Tropsch Diesel (FTD) and methanol production. Next, the details of FTD and methanol production are discussed, followed by a discussion of fuel transport and distribution.

3.6.1 Remote Natural Gas Production and Transportation

Both synthetic diesel and methanol have been produced from natural gas outside the United States. Remote locations are the likely sources of natural gas for FTD and methanol in the future.

Natural gas is recovered and collected from oil and natural gas fields. The gas is then transported by pipeline to processing facilities, which are usually located near the gas field. For commercial natural gas, the gas is processed to remove propane, butane, moisture, sulfur compounds and CO_2. However, for FTD and methanol production, CO_2 in the gas improves the efficiency of the process.

Excess natural gas from oil production operations is a likely FTD feedstock and in some instances methanol. Utilizing natural gas in this manner can eliminate flaring. Flaring natural gas can be a safety problem and flaring the gas contributes to CO_2 emissions.

When flared gas is used as a feedstock, no CO_2 emissions from the natural gas feedstock or end product fuel are attributed to the FTD or methanol product. If natural gas is extracted from locations that are not associated with oil fields, or natural gas that would be reinjected into the oil well is used as feedstocks, then CO_2 related to the natural gas is attributed to the FTD or methanol fuel.

Table 3-12 shows the natural gas transport distances and mix of diverted flared gas and new gas that was assumed for the scenarios in this study. These assumptions affect fuel-cycle energy and global CO_2 emissions. In scenario 1, 20% of natural gas feed is assumed to be associated with flared gas. Flared gas is a large potential resource for fuel production. Many oil companies and some countries such as Nigeria have instituted policies to eliminate natural gas flaring. In Scenario 2, no credit for flared gas is attributed to FTD or methanol production with the assumption that the credit for flaring could be equally attributed to oil production.

Table 3-12: Natural Gas Transportation Assumptions for FTD and Methanol Production

Scenario	1	2	3
Flared gas feedstock	20%	0%	20%
Natural gas transport distance (mi)	200	200	100
Compressor engines	55% reciprocating 45% gas turbines	55% reciprocating 45% gas turbines	50% reciprocating 50% gas turbines

Many methanol plants are currently operating and under construction. With the apparent reduced use of MTBE, production capacity may exceed demand. Some methanol plants could be converted to produce FTD so the feedstock assumptions for the year 2010 are the same.

3.6.2 Synthetic Diesel Fuel Production

Synthetic fuels can be produced from the catalytic reaction of CO and hydrogen. The FT Process is one process that has been developed for fuel production. In recent years, developments in catalysts have allowed for the production of fuels in the diesel boiling point range. Synthetic diesel and FTD are categorized together as all approaches for producing synthetic diesel are conceptually similar and result in the same emissions impact in California.

The FT Process was originally developed in Germany in the 1920s to produce diesel from coal. FT plants are also operating in South Africa to make synthetic gasoline from coal. The FT Process has three principal steps. First, a feedstock must be converted to synthesis gas, a mixture of carbon monoxide and hydrogen. Potential feedstocks include coal, biomass, and natural gas. A catalytic reactor converts the synthesis gas to hydrocarbons in the second step. The mixture of hydrocarbons consists of light hydrocarbons and heavier waxes. The majority of the hydrocarbons are saturated. In the third step, the mixture of hydrocarbons is converted to final products such as synthetic diesel fuel.

The FT Process consists of three conversions:

1. Feedstock to a synthesis gas, a mixture of CO and hydrogen
2. Synthesis gas to hydrocarbons by use of a catalytic reactor
3. Hydrocarbons to the final products, like synthetic diesel

Currently FT plants are being constructed to use remote natural gas as a feed stock. FT fuels potentially can be produced from renewable sources such as biomass. Production options are discussed in more detail in Section 4.4.

FT diesel fuel can be transported in conventional product tankers. Bulk storage, product blending, truck delivery, and local product dispensing can be accomplished with existing infrastructure. If pure FT diesel fuel is sold as a separate product, refueling stations will need to reallocate their inventory of local storage tanks or install additional storage and dispensing equipment.

FT diesel is likely compatible with existing dispensing equipment and vehicle fuel systems. However, fuel compatibility issues have not been widely documented. Some fuel compatibility problems were identified when low aromatics diesel fuels were introduced in California. Problems appeared to occur on older model diesel engines with a specific type of fuel system.

Major oil companies are supporting the development of FT fuels or gas-to-liquids (GTL) products. Shell, Exxon, Texaco, Chevron, and ARCO have built or are planning to build production facilities. Oil companies own many of the natural gas fields in the world and are interested in finding a market for the fuel. Exxon included an article describing its GTL technology in their 1998 publication for shareholders which illustrates their interest in the technology (Weeden).

FT fuels are attractive to oil companies since they improve the quality of diesel and make use of their natural gas resources. These fuels are also attractive since they can be used in existing vehicles.

FT fuels will become more widely available as more facilities are constructed to take advantage of low cost remote natural gas. The growth of the market may depend on the price of oil. Since the cost of producing FT fuels does not drop significantly with a drop in the price of oil, low oil prices have hindered the commercial production of FT diesel. FT fuels will likely be blended to produce high cetane, low aromatic diesel before they are sold as pure clean fuel alternatives. The blending approach allows for a build up of production and bulk storage capacity. If a demand for pure FT fuels develops, the infrastructure will be in place.

3.6.3 Methanol Production from Natural Gas

Methanol currently used in Canada mostly comes from Canada, with a smaller amount coming from Texas. Since transportation of natural gas from Texas is more expensive, as it usually comes by rail rather than ship, it was not considered here. It is also assumed that all the natural gas feedstock comes from Canada, and that the methanol is transported in Phase 4 from Canada to the South Coast by tanker ship.

Advances in methanol production technology will result in greater yields from steam reforming. New plants also may be built with combined steam reforming and partial oxidation (POX). The more efficient technologies are reflected in Scenario 3.

3.7 Methanol from Biomass

Considerable attention has been given to producing methanol from biomass sources. Several studies have considered biomass gasification with facilities that process over 1000 tons per day of biomass (50 million gallons per year). Potential feedstocks could be waste materials such as sewage sludge, wood waste, or energy crops (Katofsky, Ferrell). Materials such as forest thinnings, agricultural residue, and waste paper have also been considered potential feedstocks for cellulose based ethanol production in California (Perez).[8] Eucalyptus has been considered a potential energy crop for California, as it can grow without irrigation and growing trees can serve as a form of bioremediation to remove metals such as selenium from agricultural land. While more

[8] While considerable attention is being given to ethanol production from biomass resources in California, its principal use would be as a blending component to gasoline. Its primary use as a fuel for dedicated vehicles would be a blend of 85 percent ethanol and gasoline (E85). The vapor pressure of E85 is similar to that of gasoline and thus ARB did not include this fuel in the scope of this study.

emphasis has been placed on cellulose based ethanol production, methanol production remains an option with some pilot plant activities (Kinoshita, EPA 2000).

Landfill gas (LFG) has also been used as a feedstock for methanol production. An LFG-to-methanol project was planned for construction in Southern California, but permitting issues prevented to project from going forward (Wuebben). Landfill gas is either flared or used for power production. Several landfills flare a fraction of their landfill gas so it could be used for methanol production. Alternatively, hydrogen production from landfill gas has also been considered (Hummel).

Two biomass feedstocks for methanol were considered. In one case, a gasifier operates on agricultural residue, wood waste, and energy crops in the Central Valley. In another case, landfill gas is processed into methanol in the SoCAB. Table 3-13 shows the assumptions for methanol production from solid biomass. Sufficiently large production volumes were assumed for biomass-based methanol production in California, so that the fuel can be transported to Los Angeles by pipeline. The pipeline options would be much more cost effective than transporting the fuel by rail. Rail transportation was assumed for Scenario 2, while pipeline transportation was assumed for Scenario 3. Several methanol production facilities with a total capacity over 100 million gallons per year would be needed to support the construction of a pipeline. This would not be by 2010 but would be a viable if a large-scale vehicle market developed. If methanol powered fuel cell cars were available in commercial production volumes over 40,000 vehicles per year, the total vehicle population could be over 500 million vehicles with a fuel demand over 500 million gallons per year.

Table 3-13: Methanol from Biomass Gasification — Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NO_x	Marginal Emissions[a] NMOG
1	Extraction	Harvest equipment	—	—
2	Transport	Trucks	—	—
3	Production	Fugitives, compressor engines, purge gas combustion	—	—
4	Site storage	Onsite tanks	—	—
5	Transport to bulk storage[b]	Pipeline (pumps & fugitive), railcar (engine & fugitive)	M	M
6	Bulk storage	Floating roof tanks	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Underground tanks, refueling vapors and spillage	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.
[b] Railcar transport for Scenario 2 and pipeline transport for Scenario 3.

This scenario for methanol production does not appear to be a likely near term option. While there are substantial biomass resources in the State, there is more focus on ethanol production as a component for gasoline. If a fuel cell vehicle market were to develop, more attention would be given to alternative methanol production options. The impact on the results of the study is that a bulk storage facility is assumed in Los Angeles, and trucking emissions are the same as those for other liquid fuels.

LFG is a source of biomass energy that is used primarily to generate electric power. Biomass is converted to gas in landfills as the organic material is exposed to moisture and bacterial /fungal decomposition. The organic material is converted to CO_2 and methane. The gas also contains nitrogen from the atmosphere and trace levels of hydrocarbons, sulfur-containing compounds, and chlorinated compounds. LFG is either flared or used to generate electricity. Other uses of LFG include methanol and hydrogen production.

Hydrogen Burner Technology (HBT) has a contract with the SCAQMD to develop a hydrogen production system based on the POX (Partial Oxidation) of LFG. Several landfill sites have been considered as possible sites for hydrogen production. The interest in hydrogen production indicates that alternatives to flaring and power generation are of interest to landfill operators.

LFG is continuously exiting from the landfill either as uncontrolled losses, flared gas, or combusted gas for power generation. When LFG is converted to methanol, one of these pathways is interrupted. The question of marginal emissions is important for LFG as the alternative uses of LFG vary considerably. LFG is generally not vented in California, and even in rare instances where it might be vented, crediting methanol production with these emission reductions does not reflect the marginal impact of the methanol production facility. The categories of emission sources for methanol production from LFG are shown in Table 3-14. The emissions impacts of producing methanol using LFG from flared gas and IC engines are discussed below. Emission levels are quantified in Section 4.

Table 3-14: Methanol from Landfill Gas — Production and Distribution Phases

Phase	Process	Emission Sources	Marginal Emissions[a] NO_x	NMOG
1	Extraction	Landfill collection pipes	—	C[b]
2	Transport	Compressors	—	—
3	Production	Fugitives, purge gas combustion	M	M
4	Site storage	Onsite tanks	M	M
5	Transport to bulk storage	None	M	M
6	Bulk storage	None	0	M
7	Transport to local station	Tanker trucks (engines & fugitive)	M	M
8	Local station distribution	Underground tanks, refueling vapors and spillage	0	M

[a] M indicates if marginal emissions occur in the SoCAB. — indicates no marginal emissions, while zero emission sources are indicated with a 0.
[B] Methanol production from landfill gas is given a credit for the emission reductions from flaring landfill gas.

3.7.1 Flared LFG

Flaring LFG results in emissions of NMOG, CH_4, NO_x, CO, CO_2, and traces of PM. Since the gas is primarily CH_4 and CO_2, NMOG emissions are less than 20 percent of total hydrocarbons. Flares operate at relatively low temperatures so NO_x emissions are also relatively low. LFG is derived from biomass. The biomass consists of paper, food waste, wood waste, and other organic materials. The carbon is derived from CO_2 that was recently removed from the atmosphere. Therefore, flared LFG has zero net CO_2 emissions associated with it. This CO_2 is counted as biomass CO_2 in this study.

3.7.2 Electric Power from LFG

Many landfills generate electric power from LFG by combusting LFG either in IC engines or gas turbines. Producing electric power has both advantages and disadvantages for landfill operators. Noise from IC engines had resulted in complaints from citizens that have caused IC engines to be shut down and the LFG to be flared again. In the 1980s, landfills were able to secure contracts to sell electric power for around $0.10/kWh that provides for attractive economics for power generation. With electric power deregulation, the potential market price for electric power was viewed to be below $0.05/kWh. While electricity prices are currently much higher in California, uncertainty over future electricity prices as well as NO_x emission constraints may prevent further LFG power production capacity from being added.. Some facilities are integrated with sewage treatment plants, which have a high demand for electric power. Developments in the market for electric market make it unclear whether generating power from LFG will remain an economically attractive option. Therefore, new LFG capacity could be converted to methanol production.

The sulfur- and chlorine-containing compounds, as well as silocanes, while only present in ppm levels, present difficulties with emission control equipment and in some cases lead to corrosion of engines and turbines. NO_x control from LFG power generation equipment is limited. Lean-burn IC engines experience operational problems, as LFG has a much lower heating value than natural gas. Catalytic NO_x control (selective catalytic reduction [SCR]) is also not feasible with LFG without gas cleanup as the sulfur and chlorine compounds degrade the catalyst. Therefore, NO_x emissions from LFG power generation equipment are higher than other sources of electric power.

If an LFG electric power source were converted to methanol operation, the actual NO_x from the engine would be eliminated or largely reduced as the methanol reformer emits very little NO_x. However, it is likely that the NO_x from the engine is either part of an electric utility's RECLAIM mix or that the excess NO_x credits would be traded with other stationary users. Consequently, the net NO_x reduction due to replacing an IC engine or turbine with a methanol production facility is much lower than the difference between the emissions from the engine and the methanol facility. For example, an IC engine could stop operating. A small portion of its NO_x credits could be transferred to a new methanol production facility, and the balance of the NO_x could be used by an electric utility to increase power generation capacity in the SoCAB.

If LFG that was formerly used in an IC engine is converted to methanol, the net CO_2 differs from the flared LFG case. Reducing LFG electric power will result in an increase in electric power output from other sources. The new power generation mix is assumed to be the "actual marginal" power mix for the SoCAB for constant time of day power output. This mix power generation mix does not differ substantially from the power generation mix for vehicle as the majority of the actual marginal power generated in the SoCAB is from new natural-gas-fired units.

4. Emissions from Fuel Production and Distribution Processes

This section includes emissions from feedstock extraction, fuel production, and distribution. The emissions sources are covered roughly in order from extraction through distribution with some overlap. Section 4.1 reviews emission rates from equipment used in transporting feedstocks and fuel and in processing operations. Energy usage rates for transportation equipment are also discussed in Section 4.1.

Fuel production emissions and energy inputs are covered in Sections 4.2 through 4.8. The allocation of energy use to product fuels is discussed. While fuel production processes have a minor or no effect on marginal NMOG or NO_x emissions in the SoCAB, they are still analyzed as they affect global CO_2 emissions. Fuel processing is defined as the conversion of feedstock material into end use fuel, or fuel production. Feedstock input requirements also relate to feedstock extraction requirements in Section 4.1. Several fuels are processed from a combination of feedstocks and process fuels. Oil refineries and gas treatment plants produce multiple fuel products. Many production facilities import or export electricity, and excess heat energy can be exported to other facilities,

Section 4.9 discusses emissions from fuel storage and distribution. These represent the most significant sources of marginal NMOG emissions. Section 4.10 discusses toxic emissions. Since toxic emissions are not measured as frequently as criteria pollutants, these emissions are primarily available from other data sources than those in Section 4.1 through 4.9. Toxic hydrocarbon emissions are estimated as a fraction of NMOG.

Several approaches have been taken towards determining fuel-cycle emissions. Perhaps the simplest approach is to estimate the energy required for each step of the fuel-cycle. Then, "emission factors" can be multiplied by the energy use rate (Unnasch 1989). There are several negative aspects of relying entirely on this approach. Primarily, energy use expressed in Btu/gal of fuel (or Btu/Btu fuel) is many steps removed from the actual fuel-cycle-processing step.

For example, consider a diesel deliver truck with 7,800 gal of fuel traveling a 50-mi round trip route. A diesel truck fuel consumption of 5 mi/gal is expressed in energy terms as 0.0014 Btu/Btu based on lower heating values (Table 2-1). Expressing all of the fuel processing steps in energy terms allows for a convenient comparison amongst different fuel-cycle emission studies. The emissions in this study are estimated from more fundamental principles. In the case of fuel delivery trucks, a constant mileage is assumed for all fuel types and emissions are calculated from the g/mi emissions and truck fuel capacity to yield g/gal of delivered fuel.

The energy in Btu (HHV) per unit of fuel produced is tracked with the fuel-cycle emissions. Lower heating values are only used to estimate vehicle fuel consumption and are not mixed with higher heating values anywhere in this study.

Emission rates from fuel production equipment are estimated from published emission factors, other emissions data, and emission requirements from local and federal rules. In the strictest sense, an emission factor might be considered to be an energy specific emission rate, in g/gal fuel for example, that represents a wide range of equipment and is weighted according to equipment inventory, usage pattern, and other parameters. The term emission factor implies inventory wide applicability and is reserved for published emission rates.

Emissions depend on the location of equipment and the prevailing (and prior) emission standards. Vehicles and combustion equipment in the SoCAB are and will continue to be subject to the strictest emission controls.

SCAQMD limits are as stringent or more so than stationary source requirements in other areas. Table 4-1 shows NO_x limits on combustion sources in the SoCAB. Boilers and gas turbines have been subject to Best Available Control Technology (BACT) requirements since the 1980s. All equipment installed since that time would meet NO_x levels consistent with Rule 474. More recent installations will need to meet stricter NO_x limits under Rule 1134. NO_x levels of 9 ppm can only be met with Selective Catalytic Reduction (SCR), and actual emissions with SCR are one-half of this level.

Emission limits under Rules 474, 1110, 1134, and 1146 are expressed in ppm. These were converted to lb NO_2/MMBtu using a fuel factor of 8740 dry scf/MMBtu for natural gas and 9220 dry scf/MMBtu for diesel fuel. These emissions are expressed in lb/MWh or g/hp-hr for the energy consumption assumptions shown in the table.

4.1 Fuel Extraction, Transportation, and Processing Equipment

Several types of equipment are used repeatedly throughout the estimation of fuel-cycle emissions. For example, diesel powered tanker trucks are used to move diesel, LPG, and methanol fuels from storage locations. Natural gas engines and gas turbines compress natural gas and are used in a variety of fuel industry applications. These engines are used to transmit natural gas feedstock to oil refineries, FT diesel, methanol, and electric power plants. This section summarizes the emissions and estimated usage rates for various types of equipment. The usage rates are related to assumptions for different scenarios.

4.1.1 Engine Emissions

Table 4-2 summarizes the emission and performance characteristics of natural gas turbines used for natural gas transmission, prime movers. Table 4-2 shows estimate of current and future emissions for turbines operating in the SoCAB, California, and the United States. Turbines operating outside of North America are assumed to emit at 1990 United States levels.

Table 4-1: Summary of SCAQMD NOx Rules

Rule 474 — Fuel Burning Equipment — Oxides of Nitrogen

Emission Source	**Non-Mobil Fuel Burning Equipment**						**Steam Generating Equipment**	
Heat rate (MBtu/hr)	555 to 1,785		1,786 to 2,142		>2,143		>555	
Fuel	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
NO_x emissions [a]								
(ppmvd @ 3% O_2)	300	400	225	325	125	225	125	225
(lb/MMBtu)	0.37	0.52	0.28	0.42	0.15	0.29	0.15	0.29

Rule 1109 — Emissions of Oxides of Nitrogen for Boilers and Process Heaters in Petroleum Refineries

Emission Source	**Boilers and Process Heaters in Petroleum Refineries**
NO_x (lb/MMBtu)	0.03

Rule 1110.2 — Emissions from Stationary Internal Combustion Engines (gaseous- & liquid-fueled)

Emission Source	**Stationary Internal Combustion Engines**	
Energy consumption (Btu/bhp-hr)	8000	8000
Fuel	gas	oil
NO_x emissions [a]		
(ppmvd @ 15% O_2)	36	36
(lb/MMBtu)	0.134	0.141
(g/bhp-hr)	0.48	0.51

Rule 1134 — Emissions of Oxides of Nitrogen from Stationary Gas Turbines

Emission Source	**Simple Cycle**	**Simple Cycle**	**Simple Cycle No SCR[a]**	**Simple Cycle**	**Simple Cycle**	**Combined Cycle Power Plant with BACT[c]**
Unit size (MW)	0.3 to 2.9	2.9 to 10	2.9 to 10	>10	>60	>60
Energy consumption						
(Btu/bhp-hr)	13,000	13,000	11,000	11,000	5,200	5,200
(Btu/kWh)	17,000	17,400	14,750	14,750	7,000	7,000
NO_x emissions [a]						
(ppmvd @ 15% O_2)	25	9	14	9	9	3
(lb/MMBtu)	0.093	0.0337	0.052	0.0337	0.033	0.011
(g/hp-hr)	0.55	0.20	0.26	0.17	0.079	0.026
(lb/MWh)	1.62	0.58	0.77	0.49	0.23	0.078

Rule 1146 — Emissions of Oxides of Nitrogen for Industrial, Institutional, and Commercial Boilers and Process Heaters

Emission Source	**Industrial, Institutional, and Commercial Boilers and Process Heaters**
NO_x (lb/MMBtu)	0.037

[a]Energy consumption (HHV) values are shown for reference. Emission rules apply on a ppm dry volume basis. NO_x emissions are calculated from fuel factor and O_x content. For example: 300 ppm x 10^{-6} scf NO_x /scf exhaust x 1.17 scf @ 3% O_2/1 scf @ 0% O_2 x n

[b]SCR = selective catalytic reduction

[c]BACT-best available control technology. Emission levels depend upon site specific parameters. Some power plants have been built with 3 ppm NO_x.

Table 4-2: Natural Gas Turbine Emissions

Turbine Location	SoCAB		CA, U.S.	
Year	**1996**	**2010**	**1996**	**2010**
Energy consumption (Btu/bhp-hr)	**11,000**	**10,500**	**11,000**	**10,500**
Emissions (g/bhp-hr)				
NO_x[a]	0.3	0.17	1.4	0.5
CO	0.83	1.0	0.83	1.0
CO_2	600	574	600	574
CH_4	0.2	0.2	0.2	0.2
NMOG	0.01	0.01	0.01	0.01

[a] SCAQMD Rule 1134 requirements are equivalent to 0.1 to 0.5 g/bhp-hr.

Sources: Huey, A. D. Little

Emissions in Table 4-2 are shown in g/bhp-hr. These are converted to g/100 scf of natural gas transmitted with usage rates discusses later and the calculation approach in Section 4.4.

Energy consumption (Btu/bhp-hr) and emissions are based on a population profile of gas turbines used as natural gas prime movers (Huey 1993) and emissions data for individual makes and models of gas turbines. The range of energy rates for gas turbine prime movers can vary from 10,000 to 13,000 Btu/bhp-hr. Heating values for stationary equipment is shown on a higher heating value (HHV) basis that is standard practice in the U.S. Further calculations that involve lower heating values (LHV) are discussed in Section 5.

NO_x emissions for gas turbines located in the SoCAB are based on SCAQMD Rule 1134 (Emissions of Oxides of Nitrogen from Stationary Gas Turbines) and an estimate of the types of gas turbines in the region. Because the NO_x limit set forth in Rule 1134 varies according to control technology and rated power output, the NO_x emission factor is an average emission factor for several types of gas turbines with varying power output and control technologies. The future NO_x emission factor for gas turbines in the SoCAB is based on the emissions from the best available control technologies for gas turbines.

HC and CO emissions are consistent with EPA emission factors. CO_2 emissions are proportional to energy consumption.

Emissions data also shows that methane emissions make up over 90 percent of the Total Hydrocarbons (THC) emissions from a gas turbine.

Table 4-3 summarizes the emission and performance characteristics of natural gas reciprocating engines used for natural gas transmission, prime movers. Engines outside of North America are assumed to emit at the 1990 U.S. level.

Table 4-3: Natural Gas Reciprocating Engine Emissions

Engine Location	SoCAB		Row	CA, U.S.	
Year	1996	2010	1990	1996	2010
Energy Consumption (Btu/bhp-hr)	8,000	7,800		8,000	7,800
Emissions (g/bhp-hr)					
NO_x	2	0.48	6	5	2
CO	2.7	2.7	2.7	2.7	2.7
CO_2	438	427	438	438	427
CH_4	4.42	5	5	5	5
NMOG	0.45	0.5	0.5	0.5	0.5

[a] SCAQMD rule 1110.2 requirements are equivalent to 0.34 to 0.61 g/bhp-hr.
[b] Engineering estimate.

Sources: Huey, EPA 1999, A. D. Little

Energy consumption is based on a population profile of reciprocating engines prime movers (Huey) and emissions data for individual makes and models of engines. This value can range from 6,000 to 10,000 Btu/bhp-hr.

Population profiles of reciprocating engine prime movers indicate that, the majority of these engines are lean-burn, with relatively few being stoichiometric rich-burn engines. The emission factors assigned to reciprocating engine prime movers are associated with lean-burn engines. Uncontrolled lean burn engines do not operate sufficiently lean to provide significant NO_x reductions. All new lean burn engines sold in North America are configured for low NO_x emissions.

NO_x emissions outside the SoCAB (CA and the U.S.) are estimated to be 5 g/bhp-hr, which is based on an engine prime mover population and emissions profile. NO_x emissions for an uncontrolled lean-burn prime mover range from 10 to 12 g/bhp-hr, whereas the emissions for a controlled lean-burn prime mover are about 1 to 2 g/bhp-hr (Huey 1993). Future NO_x emissions for engines located in the SoCAB are estimated to 0.48 g/bhp-hr, based on SCAQMD Rule 1110.2 (Emissions from Stationary Internal Combustion Engines).

CO and HC emissions are based on EPA emission factors and CO_2 is calculated from energy consumption and fuel properties. Similar to gas turbines, the emissions data also show that methane emissions makes up over 90 percent of the VOC emissions from an engine.

4.1.2 Biomass Collection Equipment

Fuels and feedstocks are transported and distributed by a variety of equipment including trucks, trains, and marine vessels. Emissions from fuel or material transport were determined from emission rates and equipment usage factors that take into account distance traveled and cargo load. The emissions and use factors for the relevant fuels are discussed for each transportation mode. Several types of biomass are potential feedstocks for fuel production. Such feedstocks include agricultural wastes, wood waste, and purpose grown energy crops. Potential energy crops include poplar and eucalyptus. Feedstock transportation requirements for combustion of agricultural material and forest residue were used to estimate fuel usage in this study.

Emission factors from an ARB study on farming equipment are shown in Table 4-4. The study considered a range of equipment power that did not vary substantially (for the overall emission factor) in NO_x. The most prominent size range for agricultural equipment is used in this study. Typical energy consumption values are assumed for diesel equipment and increased by 20 percent for gasoline.

Table 4-4: Off-Road Equipment Emissions

Equipment Type	1996 Diesel 101-175 hp	2010 CA Diesel	1996 Gasoline 4-stroke 40-100 hp	2010 Gasoline
Energy consumption (Btu/bhp-hr)	9,350	9,200	11,200[a]	11,000
Fuel consumption (g/bhp-hr)	220	216	244	240
Emissions (g/bhp-hr)				
NO_x	11	7	3.0	3.0
CO	3.4	3.4	235	235
CO_2	640	630	720	704
CH_4	0	0	0	0
NMOG	1.1	1.1	8.25	6.6[b]

[a] 20 percent increase in energy consumption with gasoline.
[b] 20 percent reduction in mass emissions with RFG.

Sources: Kreebe 1992, EPA 1999, A. D. Little.

Evaporative emissions were estimated from ARB's study on off-road emissions. For the 40 to 100 hp category of agricultural equipment, evaporative emissions were 550 lb/unit per year, of which 98 percent were running losses. Running losses in the ARB study were based on the EMFAC emission factor for uncontrolled automobiles. The study indicates 5248 operating hours per year and 32,906 gallons per year of fuel use for 70-hp equipment. The evaporative emissions are then 7.6 g/gal. An additional 4.6 g/gal was added for uncontrolled fueling emissions from Section 4.2. Evaporative emissions for RFG- and diesel-fueled equipment were adjusted for the vapor pressure in proportion to the mass emissions in Section 4.2.

The CEC and DOE have explored numerous approaches for producing biomass feedstocks. Two studies included estimates of energy inputs for wood-based feedstock in California (Tiangco, Graham).

Usage rates for farming equipment in Table 4-5 are combined with fuel production yields in Table 4-6. The study shows diesel energy as a proxy for petroleum fuels and other energy inputs. Table 4-5 shows the energy components for diesel in greater detail. ARB's off-road emission study (Kreebe) indicates that 10 percent of agricultural equipment is gasoline-fueled. Energy requirements for biomass hauling are estimated for a truck, with a fuel economy of 5 mpg, hauling 27 dry tons of biomass over a 50-mile round trip. The energy requirements per unit of product fuel are based on the process yield considerations in Section 4.2.

Table 4-5: Energy Input for Biomass Collection

	Forest Material		Urban Wood Waste	
Energy Input	**gal/ton**	**Btu/lb Biomass**	**gal/ton**	**Btu/lb Biomass**
Diesel equipment	2.2	120[a]	1.2	70
Gasoline equipment	—	15[a]	—	8
Electricity	5 kWh	0.0025 kWh	5 kWh	0.0025 kWh
Diesel transport	0.7	37	0.86	64

[a] The split between gasoline and diesel is estimated on a Btu/lb basis from Kreebe.

Sources: Kreebe 1992, Perez 1999, A. D. Little

Table 4-6: Equipment Energy Use for Biomass Production

			Energy Consumption (Btu/gal)			(kWh/gal)
Product	**Yield[-1] (lb/gal)**	**Scenario**	**Diesel Equipment**	**Gasoline Equipment**	**Diesel Truck**	**Electric Power**
Methanol	15 lb/gal	2	1922	176	660	0.038
Methanol	12.2 lb/gal	3	1563	143	537	0.031

4.1.3 Truck Emissions

Tanker trucks are used to haul fuel for local delivery. Table 4-7 shows the emissions from heavy-duty trucks. ARB's EMFAC model estimates truck emissions for the average truckload and weight. These estimates are based on engine dynamometer results in g/bhp-hr which are converted to g/mi. The conversion factor implicitly takes into account driving patterns and vehicle loads that probably do not reflect those of tanker trucks. Recent EMFAC projections of on-road truck emissions show increases in NO_x as g/bhp-hr emission standards declined (ARB 2000a).

On-road fuel economy tended to improve over the same timeframe (Jackson).

As engine manufacturers calibrate engines for lower on-road emissions, fuel economy improvements will be limited.

Chassis dynamometer emission data for heavy-duty trucks provide some insight into expected on-road emissions.

Table 4-7: Heavy-Duty Truck Emissions

Truck Type	1990 [a,b] 75,000 GVW	1998 [c] 75,000 GVW	1999-02 [c] 75,000 GVW	2003 [c] 75,000 GVW	2010E [d] 75,000 GVW
Fuel Economy (mi/gal)	5.0	5.0	5.0	5.0	5.0
(Btu/mi)	27,560	27,560	27,560	27,560	27,560
Emissions (g/mil)					
CO	11	0.63	0.63	1.01	1.0
NO_X	23.5	23.01	13.36	6.68	7,0
PM	1.2	0.26	0.21	0.26	0.3
NMOG	1.7	0.18	0.18	0.14	0.15
CO_2	2,000	2,000	2,000	2,000	2,000

Source: [a] LACMTA data, adjusted for load (Wool) [b] Davis 1998, adjusted [c] EMFAC 2000, [d] Arthur D. Little

The Los Angeles County Metropolitan Transportation Authority has tested numerous heavy-duty vehicles on a chassis dynamometer. A series of tests were run on a truck whose emissions were tested at gross vehicle weights (GVW) ranging from 25,000 to 55,000 lb (Wool). More stringent emission controls consistent with EMFAC levels were assumed for 2010.

Table 4-8 shows the load carrying capacity of tanker trucks. The gallon carrying capacity depends on the liquid fuel density since the truck must meet axle weight requirements. The values shown in the table are typical for current fuel deliveries. For reformulated diesel, it is unlikely that the load will be varied to take into account small differences in fuel density.

Table 4-8: Tank Truck Load for Local Distribution

Fuel	Load (gal)	Fuel Density (lb/gal)	Fuel Weight (lb)	Truckload Energy (10^6 Btu LHV)
Diesel	7,080	7.2	51,000	6,550
LPG	10,000	4.2	42,000	3,470
LPG	3,000	4.2	12,600	1,040
FTD	8,000	6.4	51,400	6,110
M100	7,800	6.6	51,500	2,940

Table 4-9 shows the distances for hauling fuels by tanker truck with the assumption of a central Los Angeles fueling location. The distances are based on a typical round trip to the appropriate fuel storage site. Petroleum fuels are stored in proximity to oil refineries in the SoCAB with many storage terminals along the coast (Wilmington, El Segundo, etc.). Methanol is currently stored at a chemical terminal in San Pedro. Some finished fuels are trucked further distances.

Table 4-9: Tank Truck and Railcar Distance for Fuel Distribution

Fuel	Application	One-Way Distance (mi)	Location
Diesel	Truck to fuel station	25	SoCAB
M100 natural gas	Truck to fuel station	25	SoCAB
M100 LFG	Truck to fuel station	25	SoCAB
M100 biomass	Truck to fuel station [a]	25	SoCAB
M100 biomass	Rail from production [c]	140	CA
LPG	Truck to fuel station	25	SoCAB
LPG	Truck to distribution [b]	25	SoCAB
LPG	Rail from gas plant [c]	70	SoCAB
LPG	Rail from gas plant [c]	850	U.S.

[a]Assume that methanol is transported by pipeline and then hauled by truck.

[b]Hauling from refinery or rail car to distribution facility

[c]Includes 70 mi in SoCAB, 140 mi in CA

4.1.4 Locomotive/Rail Emissions

Several fuels could be imported into the SoCAB by railcar. LPG produced from natural gas is shipped to California by railcar. If methanol were produced from biomass in the Central Valley, railcar transport would be an option. Emissions are determined from emission rates in g/bhp-hr and cargo load factors in hp-hr/ton-mi shown in Table 4-10.

Table 4-10: Emission Factors for Rail Transport

Pollutant	Advanced Rail (g/1000 ton-mi)	(g/hp-hr)
NO_x	610.4	7.0[b]
CO	113.4	1.3
CO_2	59,906	687
NMOG	69.8	0.8
PM	8.7	001

[a]Cargo factor = 87.2 hp-hr/net ton-mi.

[b]NOx for older locomotives is 11 g/bhp-hr.

4.1.5 Marine Vessel Emissions

Crude oil and finished fuels are shipped in tanker ships. Tankers are powered by steam turbines as well as low speed diesels. The most prominent propulsion system for ocean going tankers is a two-stroke diesel (Burghardt).

Table 4-11 shows emissions from typical marine diesel propulsion engines. The NO_x emissions are comparable to or slightly higher than those from uncontrolled truck engines. Fuel consumption in g/bhp-hr is quite low. One reason for the lower fuel consumption is the higher caloric value of the heavy fuel oil used in marine diesels combined with combustion advantages of low speed operation and higher compression ratios. Fuel consumption of marine diesels has dropped from 140 down to 120 g/bhp-hr over the past two decades (compared to 215 g/bhp-hr for a diesel engine on the EPA transient cycle). NO_x levels depend on engine load over the ships operating profile. Emission factors that take into account a ship's operating profile are expressed in g/kg fuel in Table 4-12.

Table 4-11: Emissions from Marine Diesel Engines

Emission Source	Two-Stroke Diesel, Bunker Fuel	Four-Stroke Diesel, Bunker Fuel
Energy consumption (Btu/bhp-hr)	5890	6086
Fuel consumption (g/bhp-hr)	120 to 140	120 to 140
Emissions (g/bhp-hr)		
NO_x	13.4	10.4
CO	0.15	0.75
CO_2	448	463
CH_4	—	—
NMOG	0.6	0.2
PM	0.5	0.5

Source: Arthur D. Little.

Table 4-12: Emissions and Use Factors for Tanker Ship Operations

Emission Source	150,000 DWT tanker 1990 Diesel Motor	Maneuving	Tankers
At sea use factors			
Fuel consumption (kg/ton-mi)	0.0018		
Load efficiency	0.95		
Fuel	Bunker fuel		
Energy content (Btu/kg)	40,350		
At sea emissions (g/kg fuel)	**g/kg**	**lb/1,000 gal**	**lb/1,000 gal**
NO_x	70	639	639
CO	1	58	55
CO_2	3,300	—	—
CH_4	—	19	18
NMOG	4	57	57
PM	1.5	3	3

Sources: Bremnes, Pera.

Table 4-13: Emissions and Use Factors for Tug boats and ships

Emission Source	Tug boats and ships
In port use factors	
Port transit time (h)	2
Hotelling, pumping (h)	30
Tugboat operation (h)	8
Fuel use (kg/visit)	7,716
(kg/DWT)	0.051
Fuel	Diesel
Energy content (Btu/kg)	42,560
In port and tugboat emission factors (g/kg fuel)	
NO_x	37
CO	13.9
CO_2	3,200
CH_4	—
NMOG	6.9
PM	1.5

Sources: EPA AP-42, Kimble.

Tanker capacity is measured in dead weight tons (DWT) which includes the total carrying capacity of the ship. The load efficiency indicates what fraction of the total cargo capacity is actually carried. Fuel consumption decreases with larger tanker size. Tanker carrying load is measured in ton-miles. For marine applications, distance is measured in nautical miles (2000 yards), and speed is measured in knots or nautical miles per hour. For this analysis, crude oil, FTD, and methanol are shipped in 150,000 DWT tankers. Fuel consumption for tankers also varies with tanker speed and ocean conditions. Data from several sources (ARB 1990) indicate that the fuel consumption for a modern tanker is about 1.8 kg/1000 ton-mi. This fuel consumption is based on a round trip, carrying ballast on the return trip.

Tanker ships also produce emissions while in port. Auxiliary engines operate to produce electric power and tugboats maneuver the tanker into port or to the oil unloading platform. In-port time for tanker ships is generally as short as possible in order to maximize use of the tanker. In-port operation time and fuel consumption were estimated from information included in an ARB workshop on marine emissions. Tugboat fuel consumption is estimated from hours of tugboat operation and tugboat fuel consumption curves. NO_x emission factors are lower for port operations than those for at sea operations because the engines operate at lower load, use lighter diesel oil, and a different mix of engines.

Table 4-14 shows the distances traveled by tanker ships. The capacity of the tanker in gallons of product per DWT is also shown. Tankers carry about 95 percent of their weight capacity as cargo with the balance being consumables and ballast. Thus 95 percent of a short ton results in 288 gal of methanol per DWT (2000 lb/ton/6.6 lb/gal $\times$ 0.95 capacity.

Table 4-14: Overview of Waterway Transportation

Route to Los Angeles	One Way Distance (naut. mi)[a]	Cargo	Capacity (Gallons/DWT)
Vancouver, BC	570	Methanol	288
Valdez, AK	770	Crude Oil	247
Singapore	7,700	Crude Oil	247
Singapore	7,700	Methanol	288
Singapore	7,700	FTD	260

[a]Nautical Mile = 1.136 mile = 2,000 yards.

Table 4-15 shows the marine transportation distance assumptions. The percentages represent the weighted average of the shipping distance that corresponds to the locations indicated in the table. Tanker travel distance in the SoCAB is taken to be 26 nautical miles. Several studies have considered the appropriate distance to include for marine vessel inventories (Port of Los Angeles). The SCAQMD boundaries include a 32 nautical mile section towards Ventura County and an 18 nautical mi. section to the South. Other studies have drawn an 88 nautical mile radius from shore or a similar shape out past San Clemente Island. Tanker ships probably reduce their power and coast when entering port that would lead to lower emissions along the coast. A relatively shorter (26 mi) tanker travel distance was assumed for this study while tanker emissions are not adjusted for reduced load. Assuming a longer distance and lower emissions would yield a similar result.

Table 4-15: Partition of Marine Transport Distances[a]

Location	Vancouver, BC	Singapore, Indonesia	Santiago, Chile	Composite[b]
Mileage Allocation				
SoCAB	26	26	26	26
CA	530	0	100	265
U.S.	360	0	0	180
ROW	37	7620	4700	3830

[a] One-way distance, nautical miles.
[b] Mix of 50% Canadian and 50% Asian transport

4.2 Refinery Emissions

A variety of petroleum products are produced from crude oil. Refineries produce gasoline, diesel, kerosene/jet fuel, LPG, residual oil, asphalt and other products. A variety of co-feedstocks, including natural gas, electricity, hydrocarbons from other refineries, and MTBE and other oxygenates, complicates the analysis of fuel-cycle emissions. Different crude oil feedstocks, gasoline specifications, and product mixes also complicates the picture for refineries.

Determining the emissions from the production of petroleum products involved the following approach. The SCAQMD emissions inventory includes emissions from oil production, refining, and distribution. These emissions are broken down by type, e.g. fugitives from valves and flanges. Emissions from base year, 1996, is based on emission use fees from stationary sources. These values were the basis for determining emissions, on a gram per total amount of petroleum production basis. However, these emissions need to be allocated to the various refinery products in order to reflect the energy requirements for producing different fuels.

The output from a refinery model was used to determine the energy inputs required to produce different gasoline, diesel, and other petroleum products (MathPro 1999). Refinery combustion emissions were allocated to gasoline, diesel, and LPG in proportion to the energy requirements for refinery units. An energy allocation model in Volume 2 was also used to determine changes in refinery energy needed to produce diesel and LPG. This approach results in the average emissions from refineries.

Emissions from refinery units in the model were allocated to the petroleum products produced by each refinery unit. For example, all of the combustion emissions associated with the diesel hydrodesulfurization unit are attributed to diesel fuel. Table 4-16 shows the allocation of crude oil energy input and imported energy to diesel, RFD, and LPG.

Table 4-16: Allocation of Product Output and Energy Consumption for Refineries

Product	Crude Oil (gal/gal)	Natural Gas (100 scf/gal)	Electric Power (kWh/gal)	Energy[a] (Btu/gal)
Diesel	1.04	0.09	0.13	163,000
RFD	1.04	0.12	0.25	178,500
LPG	0.71	0.05	0.05	111,400

[a] Energy inputs based on allocation of energy inputs for MathPro refinery model. 103,000 Btu/100 scf natural gas and 9,000 Btu/kWh power.

Source: A. D. Little

4.2.1 SCAQMD Inventory

The SCAQMD emissions inventory provides insight into emissions from oil production, refining, and distribution in the four county SoCAB. Refineries and oil producers submit emission fee forms annually to the SCAQMD. Emissions for these forms are determined from either published emission factors or from source testing. These values make up SCAQMD's base year inventory.

Most of the emission rates are determined from calculations that depend on equipment type and throughput using SCAQMD and AP-42 emission factors. Other emissions are determined from source testing.

The SCAQMD inventory is determined for average days as well as summer and winter days. The summer inventory was examined in this study since it is intended to represent conditions for maximum ozone formation. The summer inventory may not be representative of the petroleum industry since refineries operate at fairly constant capacity and are not affected by seasonal activities. The summer inventory may also be adjusted for increases in temperature and higher evaporative emissions. Higher RVPs in the winter might cancel out the temperature effect; however, crude oil breathing losses will be higher.

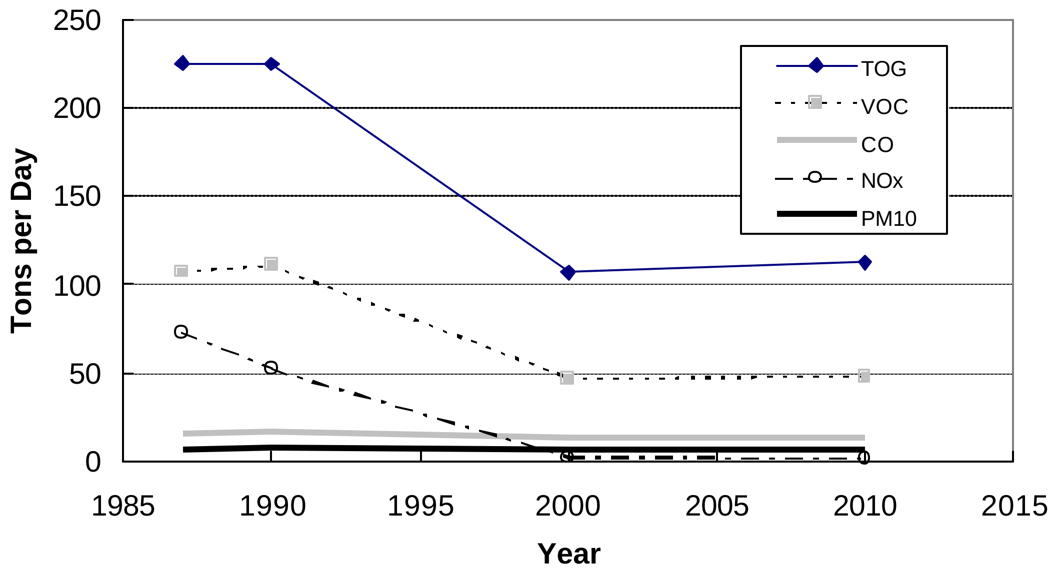
Table 4-17 shows the SCAQMD TOG and VOC summer inventory for the years 1987, 1990, 2000, and 2010 for the SoCAB (SCAQMD 1996). The inventory of TOG, VOC, NO_x, CO, and PM_{10}, is also shown in Figure 4-1. Since the sources emit hydrocarbon emissions, TOG corresponds to total hydrocarbons and VOC corresponds to NMOG. The inventory shows no reductions in VOC emissions between 2000 and 2010. This result depends on assumptions in the inventory calculations that are not readily correlated to emission rules. The inventory shows in increase in petroleum marketing emissions from 2000 to 2010, which reflects growth in gasoline demand. As discussed in Section 4.9, new ARB rules require further reductions in refueling emissions. The inventory values are shown as a point of reference while fuel-cycle emissions are based on per gallon calculations.

Table 4-17: SCAQMD Inventory for Oil Production, Refining, and Marketing

	VOC (tons/day)			
Source Category	**1987**	**1990**	**2000**	**2010**
Fuel Combustion				
Oil and gas production	0.80	0.66	0.56	0.56
Petroleum refining	1.68	1.39	1.33	1.33
Petroleum Process, Storage & Transfer				
Oil and gas extraction	38.70	43.30	11.68	11.70
Petroleum refining	23.61	21.79	9.08	9.16
Petroleum marketing	40.76	40.99	22.29	22.81
Other	1.60	2.62	2.00	2.24
Total	**107.2**	**110.8**	**46.9**	**47.8**

Source: SCAQMD 1997.

Figure 4-1: SCAQMD Inventory for Oil and Gas Production, Refining, and Marketing



Source: SCAQMD 1996.

Table 4-18 shows the VOC emissions from oil production on g/gal basis. The refining and production values in Table 4-16 are shown on a total refinery emissions per gallon of gasoline basis. These values provide a point of comparison for determining average emissions that are not a focus of this study.

Table 4-18: NMOG Emissions from SCAQMD Oil Production and Refining (g/gal)[a]

Emission Source	1990	2010
Oil production	0.449	0.277
Oil refining	0.929	0.812

[a] Total (average emissions) per gallon of gasoline.

Energy inputs for producing reformulated diesel were estimated from an EMA study on low sulfur diesel formulations (MathPro 1999). LP model runs, performed by MathPro, estimated the energy inputs for an oil refinery shown in Table 4-19. Only the energy inputs that changed with fuel formulations are shown. Diesel production was 35 kbbl/day for all of the model runs. 80 kbbl/day of gasoline as well as other products are also produced by the refinery. The energy inputs represent a relatively small fraction of the energy in the product diesel. Taking the difference between the 20 and 150 ppm sulfur case, energy inputs to the refinery are -0.2 kbbl/day of crude oil and fuel and 18 MWh of electric power. The net difference in energy input is 4000

Btu/gal of diesel or about 3 percent of the fuel's energy content. While sulfur reduction in diesel fuel requires capital equipment, the energy and emission impacts are relatively small. Additional hydrogen demand is required for desulfurization. About 500 scf of hydrogen per barrel of product fuel are required to reduce sulfur levels from 250 to 20 ppm (Dickinson). For RFD in this study, 400 scf of hydrogen per barrel was assumed as sulfur levels are reduced from 150 to 20 ppm. The primary impact on emissions is associated with natural gas distribution.

Table 4-19: Model Energy Inputs for Producing Reformulated Diesel

	150 ppm Diesel[a]	20 ppm Diesel[b]
Inputs		
Crude oil (kWh/day)	147.3	147.1
Isobutane (kbbl/day)	1.5	1.4
Fuel (kbbl/day)	12.7	12.8
Electric power (MWh/day)	776.6	794.6
Outputs		
Diesel (kbbl/day)	35	35
Sulfur (tons/day)	137	142

[a] MathPro Case 8.
[b] MathPro Case 9a.

Source: MathPro 1999

Emissions associated with reformulated diesel production were estimated to correspond to those for generating electric power for the additional energy input less a credit for the reduction in fuel input to the refinery. Emissions for producing electric power are discussed in Section 4.8.

4.3 LPG Processing from Natural Gas

The study evaluated the emissions attributable to LPG production. These emissions can be associated with the process for converting raw natural gas into market dry gas, since LPG components are removed from the gas as waste products. The propane (over 97 percent), ethane, and butane are removed from natural gas during the extraction process. In 1998, 561 million metric tonnes of gas were withdrawn from oil and gas wells. Of this, approximately 400 million tonnes were produced as dry gas, while 14 million tonnes of LPG were extracted. The LPG produced has been calculated by examining the DOE Energy Information Administration's inventories of gas withdrawn, portions removed during production, and portions removed during extraction. Methane, light hydrocarbons, and other gases are used for pressurizing gas and are lost due to venting and flaring during production. In addition, hydrocarbons are removed during the liquid extraction process and fugitive losses occur. The EIA inventories show that only 29 percent of the extracted liquids is propane. Since this is the main component of LPG, the quantity of LPG produced is much less than the total hydrocarbons extracted.

The calculations estimated that emissions associated with the LPG production are proportional to the quantity of LPG produced. Thus, 3.7 percent of the methane and CO_2 emissions during the production process could be accounted in a LPG fuel-cycle analysis. Although one could claim that the emissions are a result of natural gas production since LPG contains unwanted natural gas components, the marketability of LPG requires accountability for the emissions. It is also useful to note that without data to describe the exact losses due to each natural gas component at each stage of processing, it is difficult to calculate the specific emissions. However, it is sufficient to extrapolate from the masses of methane, NMOG, and LPG in the end products.

4.4 Synthetic Diesel Production

Natural gas is converted to synthesis gas by reforming the feedstock with steam and oxygen. Natural gas is the simplest feedstock to convert to synthesis gas since it is gas and does not need to be processed in a gasifier. This synthesis gas is over 90 percent carbon monoxide and hydrogen with traces of methane and nitrogen. The Fischer-Tropsch (FT) reactor uses iron or cobalt catalysts in a fluidized bed reactor. Excess heat from the FT reactor produces steam for the reformer. Additional thermal energy can be used to generate steam to produce electric power or provide other process heat requirements such as powering desalinization plants. Wax is converted to liquid fuels by reacting with hydrogen in the final step of the process. The energy ratio (fuel output/feedstock input) for a natural gas to FT diesel plant is about 56 percent (HHV basis). This value does not include uses for excess thermal energy.

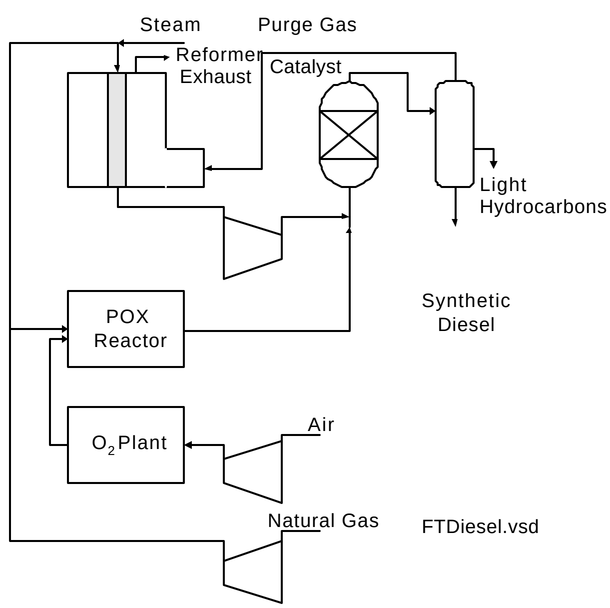
An FTD plant consists of the following processes:

- Synthesis gas production (reforming and POX)
- Catalytic hydrocarbon production
- Final product separation

Emissions from FTD diesel facilities were estimated as either combustion emissions or fugitive emissions.

Understanding the configuration of synthetic fuels plants helps illustrate the fate of carbon and net CO_2 as well as combustion and compressor engine emissions. A synthetic fuels plant with a steam reformer and POX reactor is illustrated in Figure 4-2. A steam reformer converts steam and CH_4 to CO and hydrogen. An excess of hydrogen is produced with a steam reformer. The CO and hydrogen mixture flows over a catalyst where methanol or other fuels are produced. This reaction occurs at high pressure (30 atm), as thermodynamics do not favor synthesizing methanol or hydrocarbons at low pressure. The synthesis gas may be recirculated several times over the catalyst or flow over the catalyst in a single pass (once through process). Recirculating the synthesis gas results in a higher fuel conversion rate. The power required to compress and circulate the synthesis gas is a significant energy demand. This power is provided by natural gas engines, electric motors powered by energy created at the plant, or steam-driven turbines. Excess synthesis gas contains hydrogen (since there is a stoichiometric excess) unreacted CO and CO_2, and CH_4 that was not converted in the reformer.

Figure 4-2: Process Components for Synthetic Fuel Production



Producing methanol or FTD from natural gas results in a fuel with reduced hydrogen content compared to CH_4. (While methanol has four hydrogens per carbon, it can be considered a combination of CH_2 and H_2O for this discussion.) Since the composition of the feedstock and fuel differ, a carbon balance must be used to determine the amount of CO_2 emitted from synthetic fuel production. This can be illustrated by the overall reactions for a steam reforming methanol plant.

$$CH_4 + H_2O \rightarrow CO + 3\ H_2 \quad \text{Reforming} \tag{4.1}$$

$$CO + 3H_2 \rightarrow CH_3OH + H_2 \quad \text{Methanol synthesis} \tag{4.2}$$

In practice, equilibrium and reactor volume considerations prevent all of the CO from being converted to methanol. In addition, some of the methane is not converted to CO and hydrogen. Converting CH_4 to fuels does, however, convert a significant fraction of the carbon in methane to fuel. A process is thus characterized by its energy efficiency, energy ratio, and carbon efficiency. The energy efficiency is the ratio of product output to all energy inputs to the facility (natural gas for reforming, natural gas for compressor engines and electric power). The product output can include fuel, electricity, or steam that is exported to other facilities. The energy ratio is simply the fuel output divided by the natural gas input. The carbon efficiency is the carbon in the fuel divided by the carbon in the feedstock (not counting natural gas for compressors). Higher heating values are used to represent energy efficiency in the United States and lower heating values are used in Europe. Efficiency values in this report are identified at HHVs.

Combustion emissions from FTD and methanol plants are purged synthesis gas. Since the purge gas consists primarily of hydrogen, CO_2 and CO with low levels of CH_4 and ppm levels of HCs, NMOG emissions from reformers are extremely low. Emissions estimates for FTD production are shown in Table 4-20.

Table 4-20: FTD Processing From Natural Gas

	Syntroleum Process			
Process	**Scenario 2**		**Scenario 3**	
Fuel Processing				
Electricity export (kWh/gal)	0		2.6	
Energy ratio (%)	54		53	
NG[a] feed (Btu/gal)	238,000		242,500	
(100 scf/gal)	2.31		2.35	
Emission Source	**Fugitive**	**Vent**	**Fugitive**	**Vent**
Emissions (g/gal)				
NO_x	0	0.1	0	0.1
CO	0	0.50	0	0.5
CH_4	3	0.04	3	0.04
NMOG[b]	2	0.04	2	0.04

[a]NG = Natural gas.
[b]NMOG = Non-methane organic gases.

Source: Wang, Weeden.

Steam reforming results in an excess of hydrogen for each mole of carbon. In steam reforming systems, the purge gas provides fuel to the reformer. Purge gas input to the reformer exceeds the energy requirements of the reformer for generating steam and the reforming reaction. Excess steam energy can be used to power compressors or generate electric power.

The subject of steam export and credits for steam exports is a key issue for fuel-cycle studies. Credit for steam production or electric power generation can be given for export steam. Several approaches exist for providing credits for excess process energy. The energy required to generate steam in a boiler from natural gas can be determined and used as a credit, primarily for process energy and CO_2. Also, the credit can be calculated in terms of energy required to generate electric power. Steam can only be exported to adjacent facilities. The plant is collocated with an oil refinery or chemical plant that can utilize the steam. The subject of credits for excess steam can have a significant impact on the CO_2 balance. Steam is produced from excess process heat and by burning hydrogen and has very low CO_2 emissions associated with it, because the carbon efficiency of methanol and FTD production is relatively high. If excess steam is credited with power generation from natural gas or coal, the resulting credit will increase the effective carbon efficiency of fuel production.

In this study, power requirements were matched with energy inputs within the fuel production facility. Compressors for gas circulation and oxygen plants require significant amounts of power. However, excess thermal energy is still produced in some processes. FTD production results in more excess energy as the hydrogen to carbon content in the fuel is lower than that of methanol. After all power requirements in the production facility are taken into account, excess energy is provided a credit equivalent to electric power generation from natural gas. Essentially, a synthetic fuels facility can serve to co-produce fuel and electric power. Such designs have frequently been considered. The Coolwater coal gasification facility was almost converted to co-produce methanol and electric power in 1996. Some fuel-cycle studies indicate a credit for steam generation from FTD and methanol production. The concept is to provide cogeneration steam for other applications. Steam would in principle displace the combustion of natural gas and provide a greenhouse gas credit. However, practical experience with the cogeneration of power and steam has shown the difficulty of matching a steam demand with available steam. The available heat from an FTD plant will also be low-pressure steam that will have fewer uses. For Scenario 3, the amount of FTD product is reduced to produce more high pressure steam to generate electric power. Credits for excess electric power are discussed in Section 2.3.

Synthesis gas can also be produced through a POX process. Oxygen or air is reacted with natural gas to produce synthesis gas. The hydrogen to carbon ratio of the POX product gas is lower than that of a steam reforming process. An important advantage of the POX process is that the reforming process is simplified through direct contact of the POX products in the feed gas stream. Industrial POX processes generally use pure oxygen from an air separation plant; however, POX operation with air is also possible. Operation on pure oxygen has the advantage of eliminating nitrogen from the gas stream. Nitrogen acts as a diluent that increases the requirement both for compression recirculation and for catalyst volumes.

Steam reforming and POX plants can be combined as shown in Figure 4-2. Combination POX and steam reforming systems are also possible. Combining steam reforming and POX operation allows for the production of a synthesis gas that has an optimal ratio of hydrogen to CO to improve plant efficiency. The ratio depends on the fuel being produced and the process. Combined POX and steam reformer systems are referred to as autothermal reformers (ATR).

4.5 Methanol Production from Natural Gas

4.5.1 Methanol

Methanol was first produced by heating wood in the absence of air (destructive distillation of wood) and distilling the products. In 1913, methanol was produced by passing CO and H_2 over an iron catalyst. Currently, almost the entire worldwide methanol supply is made by dissociating natural gas, primarily CH_4, into CO and H_2 with the addition of steam or oxygen (referred to as steam reforming or POX, respectively). Some CO_2, CH_4, and light hydrocarbons are also produced. This gas mixture produced through steam reforming or POX is called synthesis gas or syngas. Methanol is produced under pressure in a reactor by catalyzing the reaction of CO and CO_2 with H_2. Crude methanol produced by the reactor is then refined into chemical grade methanol.

Steam reforming of natural gas yields synthesis gas for methanol production through the following chemical reaction:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{4.3}$$

The products that are formed by the gasification of coal or biomass (CO, CO_2, H_2, H_2O and CH_4) can also be processed into suitable feedstock for methanol synthesis. Likewise, CO_2 and H_2 can be the feedstock for methanol production.

Methanol that is produced by catalyzing the reaction of CO and CO_2 with H_2 is formed through the following reactions:

$$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O \tag{4.4}$$

$$CO + 2H_2 \rightarrow CH_3OH \tag{4.5}$$

Process energy requirements for methanol production from natural gas are shown in Table 4-21.

The POX process produces a more stoichiometrically optimum synthesis gas that is fed to the methanol reactor. In this process, oxygen reacts with methane to produce two moles of hydrogen per mole of CO. The POX reactor is exothermic and does not require combustion with air. Therefore, NO_x emissions from this process are negligible. Combining a POX plant with a steam reformer is a particularly advantageous process since the exothermic heat from the POX unit can be used as energy for the steam reformer. When available, adding CO_2 can enhance the efficiency of methanol production. In remote locations, CO_2, which is about 5 percent of natural gas, is not removed from methanol feedstock (Allard).

Table 4-21: Methanol Processing from Natural Gas

Process	Steam Reforming								
	Current			Advanced			Combined POX		
Fuel Processing									
Electricity use (kWh/gal)	-0.04			-0.09			0.25		
Energy ratio (%)	66.8			68.3			72.3		
NG[a] feed (Btu/gal)	96,970			94,840			89,591		
(100 scf/gal)	0.941			0.921			0.870		
Combustion (Btu/gal)	32,190			30,060			24,820		
Emission Source	**P.V.[b]**	**D.V.[c]**	**Reformer[d]**	**P.V.**	**D.V.**	**Reformer**	**P.V.**	**D.V.**	**Vent**
Emissions (g/gal)									
NO_x	0	0	2.94	0	0	1.36	0	0	0.28
CO	0	0	0.50	0	0	0.46	0	1	0.09
CO_2	5	1	1,135	1	1	1,023	1	1	737
CH_4	2.9	0	0.04	0.29	0	0.04	0.29	0	0.01
NMOG[e]	0.4	1.2	0.04	0.04	0.12	0.04	0.04	0.12	0.01

[a]NG = Natural gas.
[b]P.V. = Purge vent. Uncontrolled emissions.
[c]D.V. = Distillation vent. Uncontrolled emissions.
[d]Reformer emissions based on 0.216 NOx/MMBtu. CO_2 from carbon balance.
[e]NMOG = Non-methane organic gases.

Source: Bechtel, Metharex 1998, Stratton, (S&T)[2]

Energy consumption data for steam reforming and POX were obtained from several studies. Natural gas reformers are fueled with process gas left over from the methanol synthesis. This gas is primarily composed of hydrogen with CO, methane, CO_2, and methanol. Emission factors for natural gas were used to estimate NO_x, CO, methane, and NMOG emissions. CO_2 emissions are determined from a carbon balance. The difference between carbon in the natural gas feed and carbon in the natural gas product is carbon in the form of CO, hydrocarbon, or CO_2 emissions. Over 99 percent of this carbon is emitted as CO_2. POX process produces NO_x emissions since combustion with air does not occur. A small amount of pollutants are emitted from flaring purge gas.

Methanol plants can be either importers or exporters of electricity. Power generation emissions associated with net electric power were included with the fuel production emissions. Electricity demand for the POX process includes required energy for an oxygen plant.

The energy input for methanol production depends largely upon the production technology. In some cases, waste CO_2 (perhaps from an oil field), can be added to the feed stream to generate a CO/H_2 mixture that has a higher methanol yield.

The energy input for methanol production only affects global CO_2 emissions. The technology for methanol production facilities does not affect emissions in CA. Total CO_2 and hydrocarbon emissions are presented in the Methanex annual report. These emissions combined with the amount of methanol produced could provide a comparison to other estimates of methanol production emissions. Emission estimates are based on design studies performed for DOE (DOE 1985). California state agencies and energy companies also supported an evaluation of large scalefuel grade methanol production (Bechtel 1988). This study provided information of energy inputs for methanol production which are in agreement with studies performed for Methanex by (S&T)[2]. Addtional information on methanol production emissions are found in Volume 2.

4.6 Methanol Production from Landfill Gas

Methanol can be produced from landfill gas through a steam reforming or POX process similar to the synthesis from natural gas feedstocks. Emission estimates for a landfill-based methanol production facility are shown in Table 4-22.

Table 4-22: Landfill Gas from Biomass

Process		Steam Reformer Methanol Plant	Avoided Emissions
Fuel Processing			
Electricity use (kWh/gal)		1.87	0
Energy ratio (%)		60.4	—
Feedstock (Btu/gal)		107,300	107,300
Feedstock (lb/gal)		2.22	2,2
Net combustion (Btu/gal)		38,000	107,300
Emission Source	**Vent**	**Process Gas Combustion**	**LFG Flare**
Emissions (g/gal)			
NO_x	0	0.52	1.5
CO	0	1.7	3
CH_4	0	0.7	1.5
NMOG	0.03	0.04	0.09

Source: Wuebben

4.7 Methanol Produced from Biomass Gasification

Synthesis gas from coal gasification can also provide a feedstock for methanol production. Numerous coal gasification systems have been studied and many of these considered for methanol production plants. Table 4-23 shows energy inputs and emissions based on several methanol production studies. Distillation vent emissions are taken to be the same as those from natural gas to methanol facilities. Similar to the POX process, no air combustion occurs and exhaust emissions are minimal. CO_2 is produced in a shift reactor or left over from methanol synthesis and emitted from a purge vent.

Table 4-23: Methanol Processing from Biomass

Process	Scenario 2 IGT Fluidized Bed		Scenario 3 Shell Entrained Bed	
Fuel Processing				
Electricity use (kWh/gal)	1.56		1.74	
Production (kWh/gal)	0.79		0.67	
Energy ratio (%)	52.4		64.7	
Feedstock (Btu/gal)	123,057		99,663	
Feedstock (lb/gal)	15.0		12.2	
Net combustion (Btu/gal)	16,690		2,667	
Emission Source	**Vent**	**Process Gas Combustion**	**Vent**	**Process Gas Combustion**
Emissions (g/gal)				
NO_x	0	0.76	0	0.12
CO	1	0.26	1	0.04
CH_4	0.29	0.02	0.29	0.003
NMOG	0.04	0.02	0.04	0.003

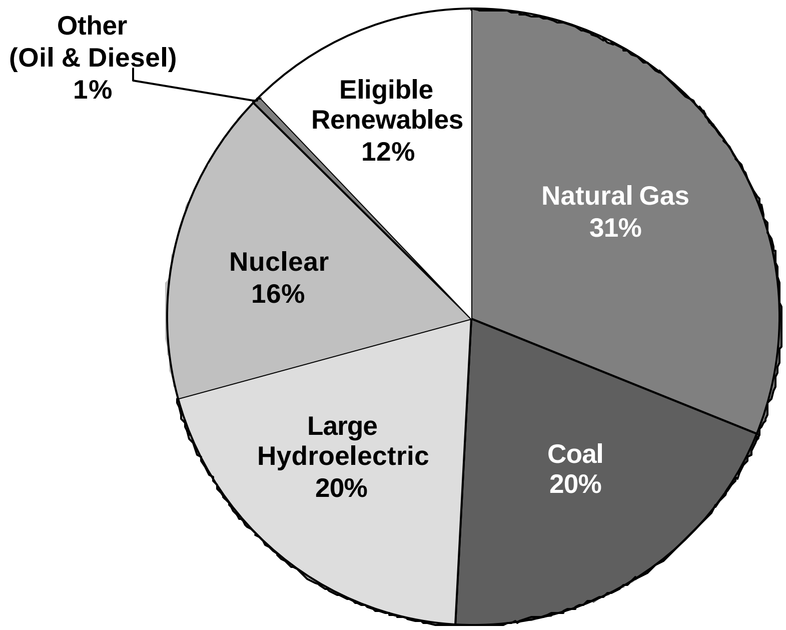
Co-producing methanol and electricity provides an opportunity to balance the load from coal gasification systems. With this process, synthesis gas from the gasifier is passes over a methanol catalyst and the unreacted gas burned in a power plant. The Air Products liquid-phase methanol (LPMEOH) process is particularly suited for once-through-type operations since a high methanol conversion can be achieved in a single pass through the catalyst. Biomass co-feedstocks such as sewage sludge have been considered as feeds for coal gasifiers but were not evaluated in this study.

4.8 Electric Power Generation

Because electric power is produced from a diverse mix of generation types, determining the energy inputs and emissions associated with EVs requires understanding what sources of generation contribute to the EV mix. Modeling the power generation and source mix associated with EV production is complex since current generation statistics have little bearing on marginal power generation.

In California, power is generated from a mix of natural gas, hydroelectric power, coal, nuclear power, biomass, and other renewables (see Figure 4-3). Hydroelectric power represents about 20 percent of power generation in California. Operating costs for hydroelectric power are very low, and all water that is available for hydroelectric power is used to generate electricity. Nuclear plants are operated at a high capacity factor and do not contribute to marginal power for any new load such as EVs.

Figure 4-3: Electricity Generation Mix in California, 1999



Source: CEC.

Several renewable sources provide power in California. Renewable resources are generally not dispatchable, some because of operational constraints, and others because of contractual requirements. While renewables are often higher in cost, cost is not the reason why they are not marginal resources. Geothermal is the largest source of renewable power in California. Geothermal is intended to operate at capacity and does not contribute power on the margin. Similarly, wind and solar power are intended to operate at capacity. Both of these generation sources do not contribute to nighttime charging. In the 1990s, 700 MW of biomass power generation operated in California. This source of power is more costly than other sources; so an increase in power demand alone will not result in additional biomass power production.

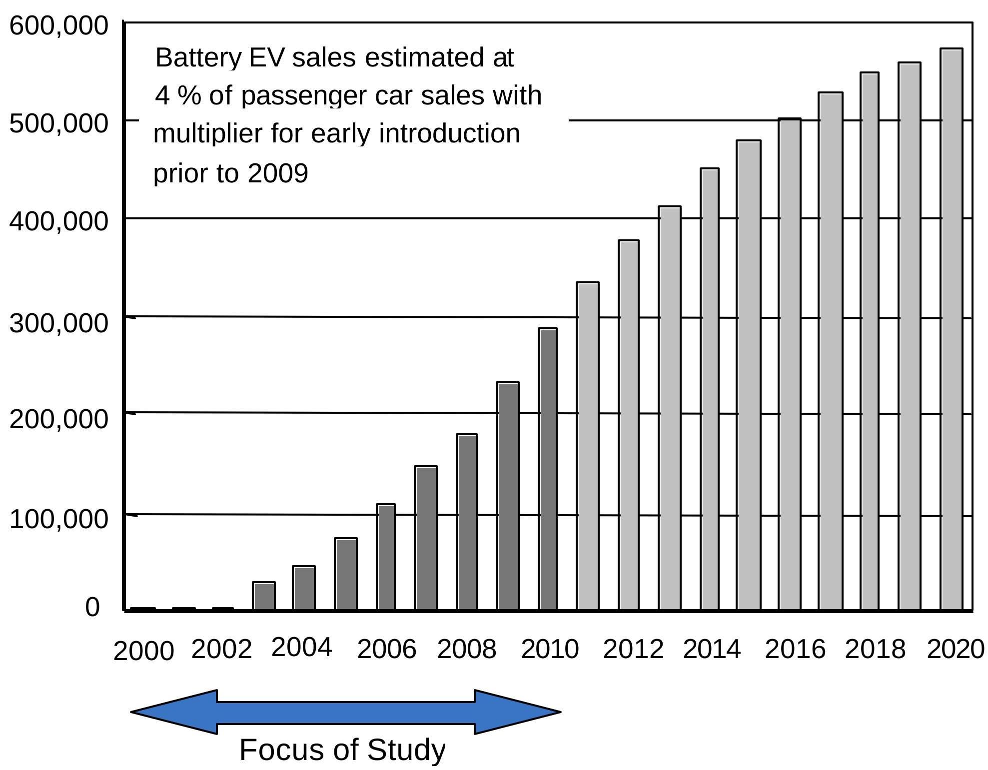
Natural gas and coal provide the balance of generation resources for California. The mix between coal and gas based production depends on the prices of these fuels as well as environmental and economic factors that affect power plant operation. While few coal-fired power plants operate in California, coal power plants in neighboring states participate in the California power market. Their output increases or decreases due to load but will not directly change emissions in California. Due to trends in emission requirements, investor concerns over future standards, and the potential for required CO_2 reductions, few new coal power plants are likely to be built. Conversely, higher natural gas prices provide incentives to consider coal power plants.

4.8.1 EV Power Demand

In order to determine the amount of electricity that electric vehicles may draw from power plants in the year 2010, many assumptions were made about the number of EVs that are expected to be connected to the grid, their operational efficiency and likely annual miles traveled. These assumptions were included in a simple probability model that calculates the effect of uncertainty on a range of predicted outcomes. Appendix C includes an assessment of the many combinations of assumptions generated with this simple probability model. The results show that, under various combinations of assumptions, approximately 1,000 GWh (1,000 GWh = 1 billion kWh) per year of electricity consumed by EVs is the approximate mean of various combinations of the EV assumptions. This EV demand assumption is less than half a percent of the 300,000 GWh of projected electricity demand in California for the year 2010.

Figure 4-4 illustrates the projected EV population in California based on introductions in accordance with the May 2000 LEV II requirements. The rate of growth drops off after 2014 once older vehicles begin to retire from the population. The ZEV requirements have been revised by ARB which will result in even smaller demands on the power generation system.

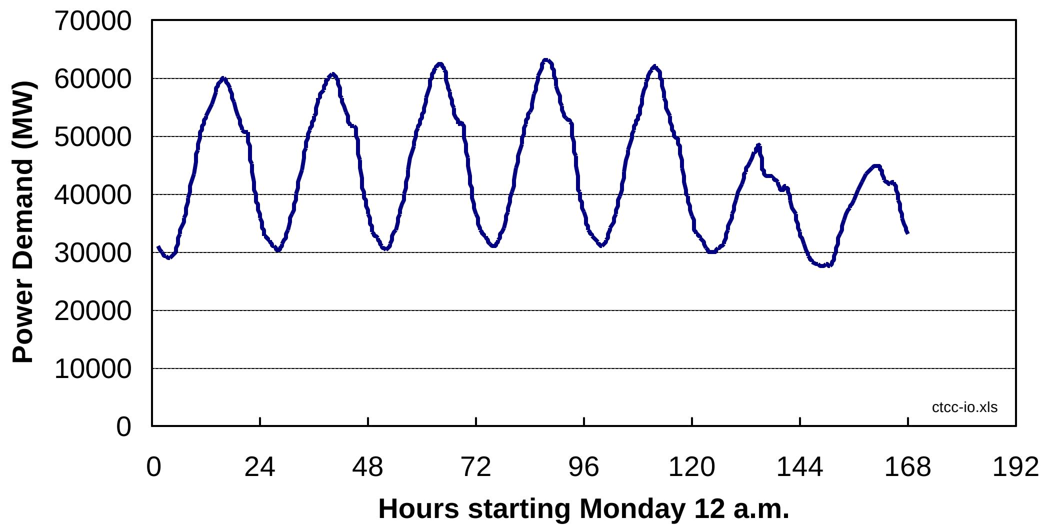
Figure 4-4: Estimated EV population in California



Source: Arthur D. Little

Figure 4-5 lists projected power demand for a week in August 2010. Power demand rises during the day and drops at night due to air conditioning and other loads. Weekend loads are lower due to less business activity.

Figure 4-5: Weekly Electricity Demand in California for August 2010



Source: CEC.

The time of day that EVs are charged is expected to have a significant impact on which power plants provide marginal power for EV charging. When charging at night, overall total power demand is lower and the generation system is operation at lower capacity. Generators with a lower cost of production would be expected to produce more power when demand is low and prices are lower. However, other constraints on the power generation system also affect which plants will operate. Some facilities operate because of contractual reliability requirements even though they may not have the lowest operating costs. Older steam boiler (Rankine cycle) facilities operate all night at part load in order to be ready to meet peak load requirements. These facilities may contribute to marginal nighttime generation.

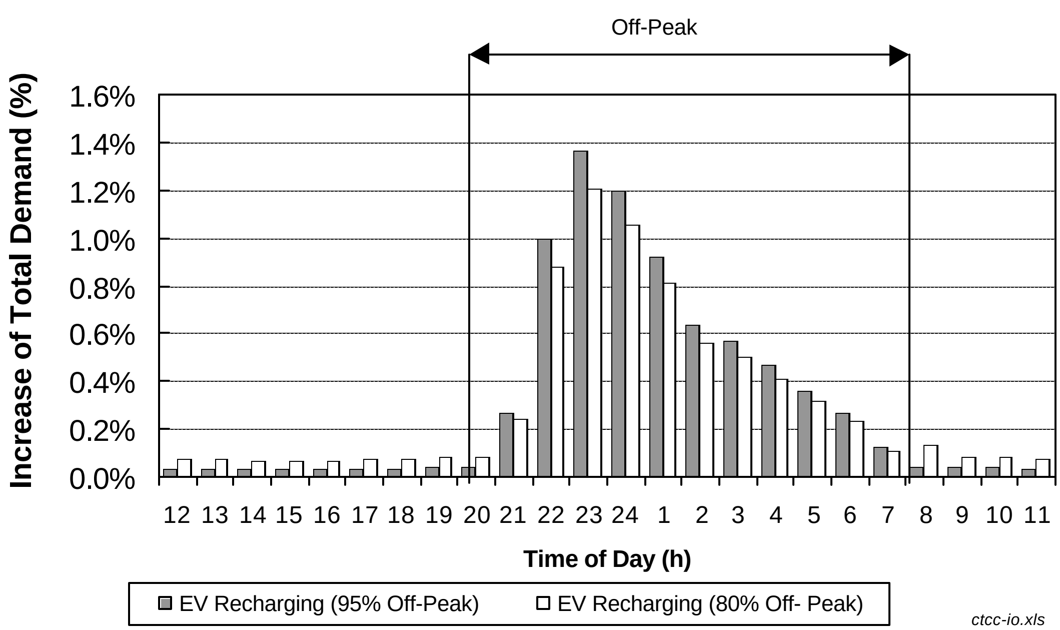
A power producer, who operates a variety of facilities, will develop a schedule of which facilities to operate. This schedule will be consistent with bids to the independent system operator (ISO). Power production is generally scheduled to correspond to the lowest cost of production, subject to a variety of other factors such as transmission constraints and requirements to idle older Rankine cycle facilities to meet next day peak load requirements.

Modern combined cycle plants are designed as base load or mid load facilities. Base load combined cycle plants will generally be the lowest cost to operate and will be run at full load throughout the day. Modern combined cycle plants that are designed to meet mid load operation can be come on-line within an hour and are often not operating at night. Consequently, it is possible that older Rankine cycle plants can contribute to nighttime generation. This scenario depends on the outlook for power plant repowering in California.

In power markets outside, older Rankine cycle plants are scheduled for repowering with combined cycle units. The willingness of power producers to make such modifications depends on the structure of the power market (such as capacity payments or producer of last resort agreements) as well as perceived risk to investors. With the current shortage of power generation, it is expected that existing facilities could be maintained rather than repowered for many years. Some utility representatives argue that the facilities in California are so old that repowering them is unavoidable. Repowering older facilities is addressed qualitatively in this study.

Since the time of day that EVs are charged affects which facilities operate and related emissions, different EV charging scenarios have been considered. EV charging is typically characterized in terms of profile that characterizes what time of day vehicles are charged. Two estimated charging profiles are shown in Figure 4-6. These profiles are based on EVs charging during 95 percent off peak/ 5 percent peak and 80 percent off peak/20 percent peak periods.

Figure 4-6: Estimated EV Charging Profiles



Source: Arthur D. Little.

The actual extent of EV charging is unknown and requires further data collection and evaluation. CEC staff surveyed EV owners and found that they are taking full advantage of time of use metered rates and recharging their vehicles during off peak hours. Some EV users describe a driving pattern that supports primarily nighttime and early morning charging. EV drivers would plug in their vehicle at night where charging would start after peak periods ended based on a timer that is synchronized with a time of use pricing. The EV may also be charged at work where it would likely be plugged in early in the morning and receive a full charge by noon. Even though charging after 8 am is often classified as a peak period, the demand for power is still low until late in the afternoon.

A higher use of peak power can also be envisioned. Electric utilities and California State agencies are also working on providing public charging infrastructure. ARB's 2001 ZEV infrastructure report indicates that nearly 1000 public chargers are installed at 500 locations which is about one-third of total estimated EV chargers in California. Presumably as EV population grows, public infrastructure will not match this pace of growth; however future customer preferences for opportunity charging are unknown. The following discussion provides an indication to the effect of off peak charging on energy consumption and emissions.

4.8.2 Approach for Analyzing Power Generation

The difference in total generation with and without EVs reflects the energy and environmental impact of EVs. While this notion is simply stated, determining where the power is generated has been the subject of considerable debate among energy companies and policy makers. Estimating the impact of generating power for EVs is fundamentally complex. Ideally power generation with and without EVs should be compared and the emissions determined per kWh generated for EV consumption. Unfortunately predicting the power generation is subject to several uncertainties and modeling constraints. Three principal approaches were used to evaluate power generation emissions and are summarized in Table 4-24 and discussed in the following sections. The dispatch modeling results are the basis for all of the emission estimates in this study.

Table 4-24: Methods for analyzing power generation

Method	Analysis Tool	Analysis Date	Scope
CA Dispatch model	Multisym TM/RAM	September 1999	Marginal 2010 generation, 95/5 mix
CA Dispatch model	ELFIN	June 1995	Marginal 2010 generation, 95/5 mix Marginal 2010 generation, 80/20 mix Average 2000 generation
Assume new plants	Heat rate data	January 2001	Heat rate for new natural gas generation
Supply Curve	Multisym TM Data	April 2001	Supply and load curve for SCE region, 2003 generation mix

Source: Arthur D. Little.

An important distinction is that the specific generation that corresponds to EV charging is not so important as the difference between total generation with and without EVs. Some efforts have been made to relate specific generation resources to nighttime generation for EVs. However, matching limited generation resources to EV demand may be a misleading accounting exercise as the net change in total generation resources is most relevant.

4.8.3 System-Wide Dispatch Model of Power Generation

CEC has evaluated the emissions for charging EVs using models that assess which power plants are dispatched as a function of load. The system load for all of California is estimated with and without EVs. The energy consumption for each power plant is determined according to the load, which is predicted for every hour within a modeling day. Power plants are determined to be generating by their operating cost. As more power is demanded in the system, more costly power is dispatched. The modeling takes into account the costs for each block of power generation for each power plant in the generation system.

Marginal emissions are a function of the characteristics of power plants that are added to or forced out of the mix, or have different loads with additional demand. The marginal emission outputs from the MultiSym^{TM} model reflect these resource plan using a generation mix discussed in Appendix B in Volume 2. The model tracks the load and the costs of operation, and optimizes power generation, based on a combination of technical characteristics and least cost, which is generally associated with the most efficient plant.

EV charging is expected to occur largely at night. The convenience of home charging and possible utility incentives to shift loads to enable time of use charging will help assure that most charging occurs in off-peak hours. The availability of generation resources is affected by capacity utilization. Since nighttime demand could be as low as one-half of peak demand, a variety of generation resources are available to meet marginal EV demand.

Emissions are determined from emission factors in lb/MMBtu multiplied by heat rates in Btu/kWh. CEC's analysis of generation emissions is presented in Appendix B. Table 4-25 compares the results for the CEC analyses performed in 1995 and 1999. The assumptions on the generation mix and the modeling tools vary between these analyses. Assumptions such as total system load and total power plants that are on line will affect the fraction of power that is generated in the SoCAB as well as the heat rate of the generation mix. The number and type of plants that are operational is a key uncertainty that affects the results of this study. The results represent the difference between all power plants operating in the SoCAB with and without EV demand added to the total load.

Table 4-25: Emissions Associated with Power Generation, Dispatch Model Results

	1995 study	1995 study	2001 study
Peak/Off peak	80/20 Charging	95/5 Charging	95/5 Charging
SoCAB Generation	49.0%	57.7%	26.0%
Emissions in SoCAB			
NO_x (g/kWh to EV)	0.048	0.041	0.070
NMOG (g/kWh to EV)	0.008	0.012	0.007
Power Plant Factor			
NO_x (g/kWh)	0.099	0.071	0.268
NMOG (g/kWh)	0.016	0.021	0.029

Source: Unnasch, 1996, CEC, Arthur D. Little.

Table 4-25 indicates how the dispatch model results are sensitive to scenario assumptions. In the 1995 study, when more charging was on peak (80/20), the fraction of generation in the SoCAB decreased with a very small change in EV demand. The 1999 modeling predicted that more generation for off peak power would come from outside the SoCAB. The NO_x emission rate was consistent with older steam boiler power plants and is relatively high. These results can be affected by a single power plant being included in the assumed mix of plants that are dispatched. The dispatch model results appear to be governed by older Rankine cycle plants, which operate at low load during the night.

NMOG emissions for the 1999 study, when compared on a composite lb/MWh basis were higher for the 1999 study. NMOG emissions from natural gas fired power plants are expected to be 1 ppm (Keese) which translates into about 0.004 lb/MMBtu. Assuming a heat rate of 9000 Btu/kWh (consistent with the dispatch model assumptions), 1 ppm of NMOG corresponds to 0.0016 g/kWh.

The 1999 incremental results are similar to those results generated in the CEC's 1995 EV report on a g/kWh in the SoCAB. There is a substantial difference in the mix of incremental energy imported from areas outside of California. The majority of imported energy to meet a slight increase in off-peak demand tended to be gas-fired. Previously, a constant mix of gas, hydro and coal-fired generation from imported energy was assumed.

Increasing energy consumption by 1,000 GWh annually throughout California in 2010 has a very small effect on marginal emissions for the entire WSCC region. For any relatively small amount of off-peak energy demand, the marginal power plant will most likely be gas-fired. The fraction of imported power has a significant effect on marginal emissions in the SoCAB. About 26% of the power for EV charging is generated in the SoCAB based on the most recent analysis and was assumed for Scenario 3. For Scenario 2, 50 percent generation in the SoCAB was assumed.

The results of dispatch modeling studies can be sensitive to specific units that provide power to meet EV load. Since the dispatch models for the State include many inputs it is difficult to interpret which generation units contribute to the EV load. Analyzing heat rates from a supply curve of generators could provides more insight into the source of generation and is discussed in the following section.

4.8.4 Supply Curve for Power Generation

Comments from the utility industry indicated that more power plants would be available by 2010 than assumed in the analysis presented in Section 4.8.4. Additional gas fired power plants and repowering older facilities would make more high efficiency facilities available for nighttime generation. At this time the mechanisms for funding the construction of new power plants is unclear. Some analysts indicate that older power plants will not be repowered because independent power generators paid substantial sums for these facilities and further investments would not be warranted. Analysts from the utility industry indicate that the many facilities are over 40 years old and need to be repowered in order to maintain reliability. Currently, many peaking facilities are being installed to provide power during periods of high demand. These facilities would likely not provide additional generation at night. A listing of power plants in California and the WSCC are presented in Appendix C.

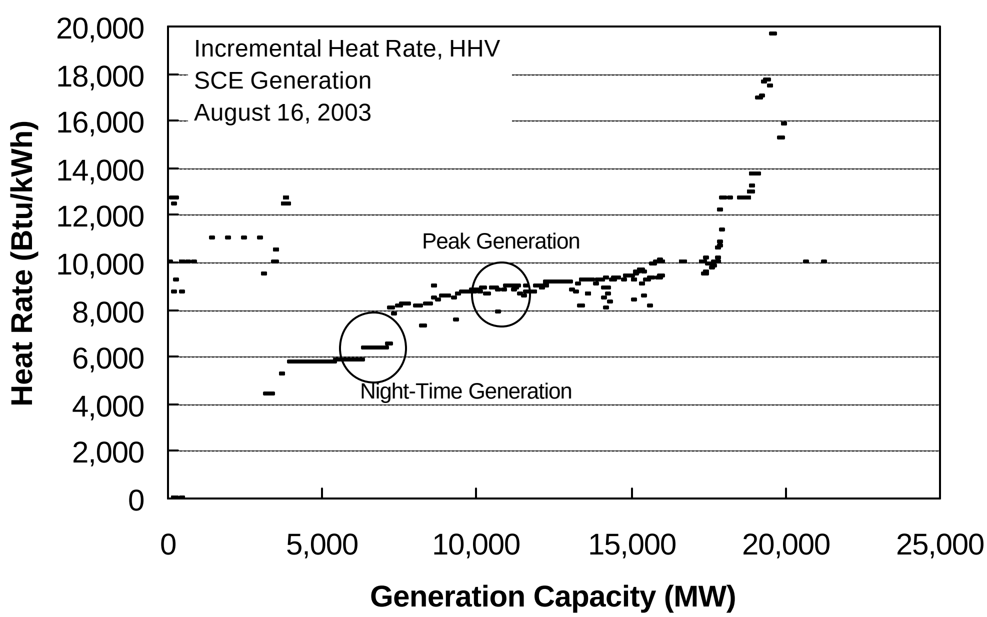
Comments from other industries indicated concern over the notion that EVs would be largely charged at night. Charging EVs during peak hours would increase power demand and result in generation from more costly producers that would be in principle less efficient. During a power shortage, additional demand during over-capacity periods contributes to higher prices and potential system disruption. Current EV demand is however too low to be considered a significant contribution to the power shortage in California. While more quantification of EV charging would be desirable, even by 2010, EV demand will be less than 1 percent of the total load. The scenarios for charging, shown in Figure 4-6 indicate less than a 0.2 percent increase in load during peak times. This level of power consumption will likely be even lower with EV sales that are expected with revisions to ARB's ZEV rules.

Due to concerns over the mix of generation and the time for EV charging, an additional analysis of EV generation emissions was performed. This information reviews the heat rates for power plants which affect emissions to give the reader a sense of which power plants could be contributing to emissions. No further emission calculations are performed. CEC provided a supply duration curves for the Southern California Edison (SCE) service area. Four supply curves were generated to represent capacity in February, May, August, and November 2003. The CEC felt that the projections for capacity were sound through 2003 but projections beyond this timeframe were uncertain without extensive further analysis of capital expenditure scenarios.

The supply curves list all of the generation resources in the SCE region, ranked by production cost. As discussed previously, cost is not the only criteria for dispatching power plants and this information only provides an indication of the types of power plants that would be contributing to the generation mix in SCE's service area. The incremental and average heat rates for each generation block are determined and presented in Appendix C. Incremental heat rates correspond to the additional energy generated per unit of additional power generated. Thus, if a fixed number of power generators are operating to meet an additional EV demand, the energy requirement to charge the EVs corresponds to the incremental heat rate. The average heat rate corresponds to the total energy input divided by the total power output for a power plant. If EV power demand were sufficiently high to require a facility to be added to the generation system, the average heat rate would be more representative. Examples of the incremental and average heat rates for individual facilities are shown in Appendix C.

Figure 4-7 shows the incremental and average heat rates for generators in the SCE region for August 2003. Each generation block was ranked by production costs (with CEC's model) and the corresponding incremental heat rate is shown versus cumulative generation capacity.

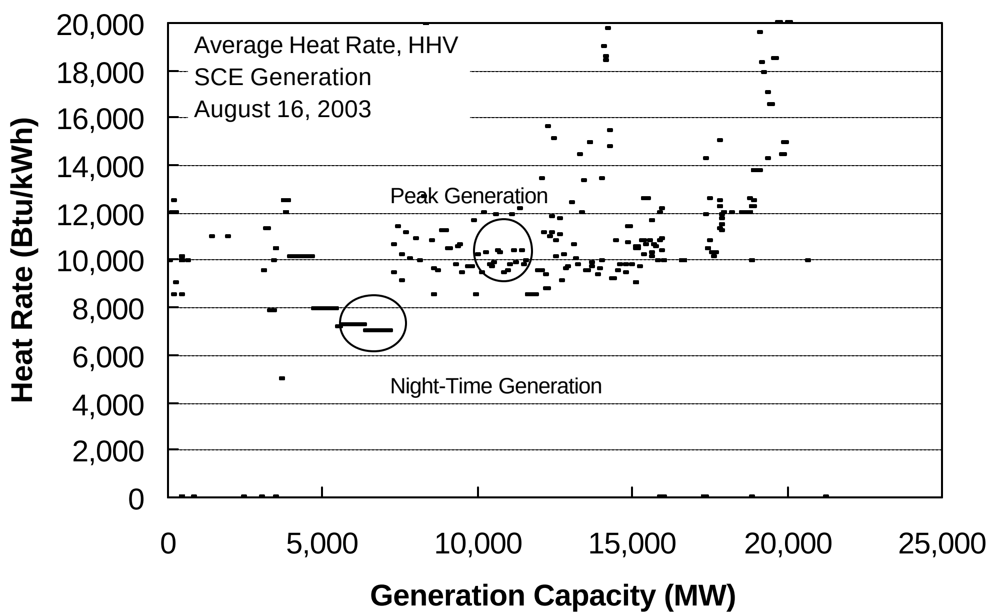
Figure 4-7: Incremental Heat Rate (HHV) for SCE Generation Region



Source: CEC, Multisym Run, April 2001, SCE_Supply.xls

Figure 4-8 shows the average heat rate for the power generation supply curve. Average heat rates are higher as these reflect units coming on-line. The impact of EV charging lies between the average and incremental heat rates. Additional heat rate curves are presented in Appendix C for other months. The supply curves do not reflect capacity shut downs for maintenance or unplanned idling. There is typically no planned maintenance in the high demand summer months and many planned shutdowns are scheduled for early in the year. Hydroelectric power tends to make up for the plants that are not operating (all of this power is used and does not contribute to EV charging on the margin).

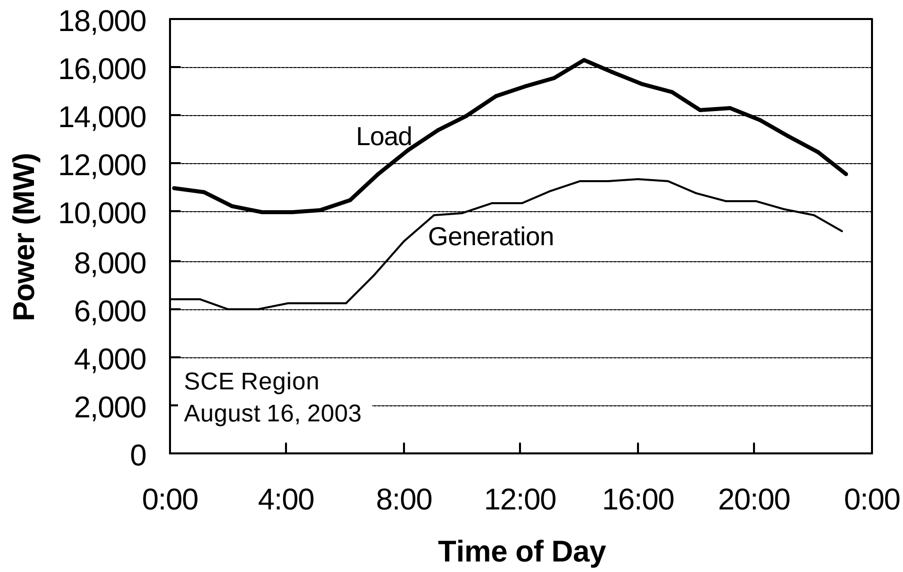
Figure 4-8: Average Heat Rate (HHV) for SCE Generation Region



Source: CEC, Multisym Run, April 2001, SCE_Supply.xls

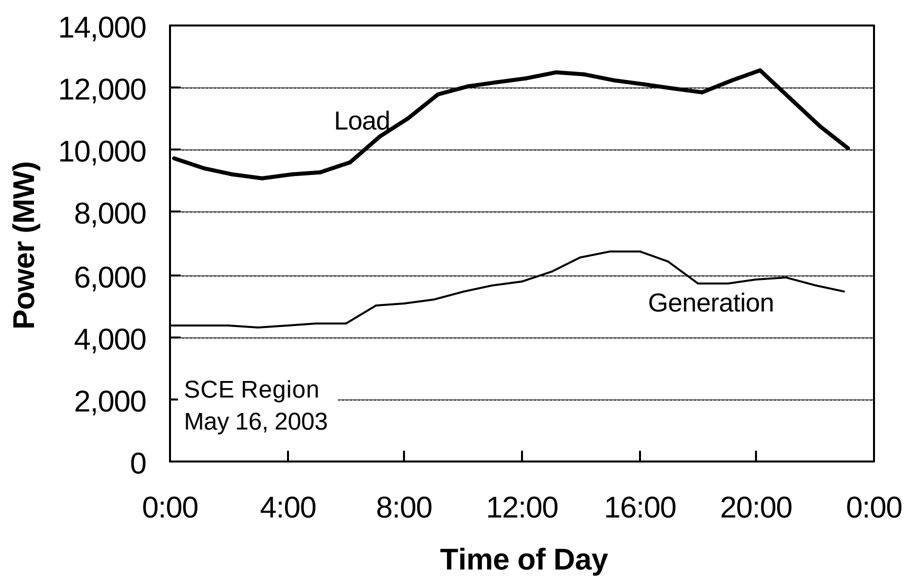
Figures 4-9 and 4-10 show the projected power demand (load) and the generation in the SCE service area. This load estimate is a projection for a typical day. Extreme power demand days that would correspond to unusually hot weather are not reflected here. The supply curve provides an indication of the optimal heat rate that could be available; however, dispatch considerations govern the mix of power plants that would be available to meet additional EV demand. Appendix C in Volume 2 presents the projected load and generation for the SCE area during four months in 2003.

Figure 4-9: Power Generation and Load in SCE Service Area (August 2003)



Source: CEC, Multisym Run, April 2001, SCE_Supply.xls

Figure 4-10: Power Generation and Load in SCE Service Area (February 2003)



Source: CEC, Multisym Run, April 2001, SCE_Supply.xls

In 2001, there was a shortage of hydroelectric power, which contributed to substantial power shortages early in the year. Scheduled plant shut downs as well as other constraints on power generation resulted in a shortage of supply. Unseasonable warm weather resulted in higher demand. The higher demand combined with a shortage of capacity resulted in the power system operating under a stage 3 alert for several days. This situation is an example of how the generation system can be operated at its limits. Under such shortages one would expect less efficient generation resources to contribute to the load. In principal, active time of use metering could result in a more optimal use of generation capacity for EVs. This concept requires further analysis.

Table 4-26 shows the projected generation and fraction of total load for the SCE area in four months (projections for individual days). This generation occurs in California, not only the SoCAB. The average value is 63.4 percent which is consistent with generation in the SoCAB of less than 50 percent of the power. An analysis of the specific units that correspond to the supply curve was not considered as this approach would be too dependent on load assumptions.

Table 4-26: Projected Generation in SCE Area

Month[a]	Off Peak Generation (MW)	In-Basin Generation[b] SoCAB/Total
February	5100	49.3%
May	4400	51.4%
August	6400	70.8%
November	7600	82.0%
Average	5900	63.4%

[a]16th day of each month, 2003
[b]Weighted 95/5 EV generation for SCE/Total

Source: Appendix C

4.8.5 New Natural Gas Power Plant Heat Rate

Considerable review of the data and comments from utility experts indicated that the input list of new generators used to develop the supply curves was conservative. Older, less efficient plants may contribute more to the generation mix. This results in a greater challenge to determine the fuel source for delivered electricity at any particular time or place. The fate of some older power plants purchased from utilities by independent power producers is also unclear. It is difficult to know whether they will be in operation in 2010. It is also unclear whether the hydropower plants, currently owned by one utility, will be auctioned to several buyers or how they might operate under new owners. Appendix C includes a list of projected capacity additions in the WSCC and in California. The reader can compare these projections with the plants that make up the supply curve in Appendix C.

Figure 4-11 shows the inventory of power plants that contribute to the supply curves. Over 7000 MW of generation capacity that is projected to be operational in 2003 was built before 1970. By 2010, representatives from the utilities suggest that these plants may be repowered. The heat rates for these older power plants are shown in Figure 4-12.

For these reasons, additional information on the technical characteristic of new gas-fired generic combined cycle plant are provided in this study.

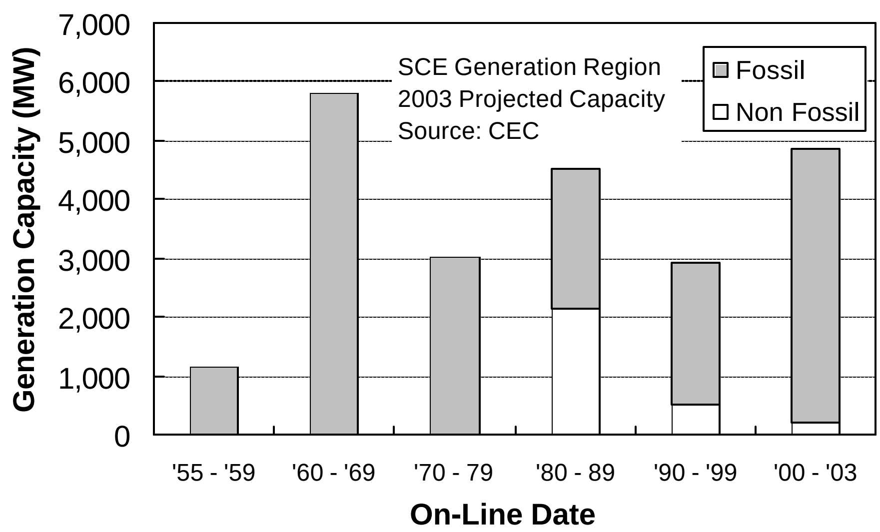
Marginal generation emissions could be lower if of a significant number of new plants are built and others are repowered by 2010. In practice many planned capacity additions do not take place so the trend in power plant repowering is a key uncertainty in this study. Most of the power plants in California are more than 30 years old and some are more than 50 years old. In the western United States, more than 60 new plants are under consideration for permits at this time for repowering and new construction. Almost all of these plants are natural gas combined cycle plants

An ideal power plants for meeting the nighttime EV recharging demand would be a new combined cycle natural gas generator. They have low heat rates (high efficiency) and can be started up and shut off over short periods. The ability to start up quickly could remove mid-load units from the generation mix at night until older steam units are repowered. Figure 4-13 shows generic heat rates for new combined cycle and combustion turbine power plants at various load levels. Obviously, determining which plants to operate to meet EV recharging demand is a complex problem that is compounded by issues other than emissions reduction, such as cost and availability.

Efficiencies and heat rates are shown on a higher heating value basis.[9] Combustion turbines operate at a peak efficiency of 35 percent. These units ideally are used for load following. Combined cycle power plants have peak efficiencies ranging from 49 to 57 percent. These efficiencies are reduced at part load operation, as indicated in Appendix C. Most of the new facilities under construction are the F type turbines with a peak efficiency of about 54 percent. The peak efficiency of power plants depends on several factors other than load. The type of cooling approach is important as cooling water is a limited resource. Power plants that have access to river or ocean water for cooling do not need to operate cooling towers, which contribute a parasitic load that reduces efficiency. Power plants can also be designed with air cooling if water is unavailable or too costly. Such a configuration is more costly and less efficient than water-cooled designs and not the preferred.

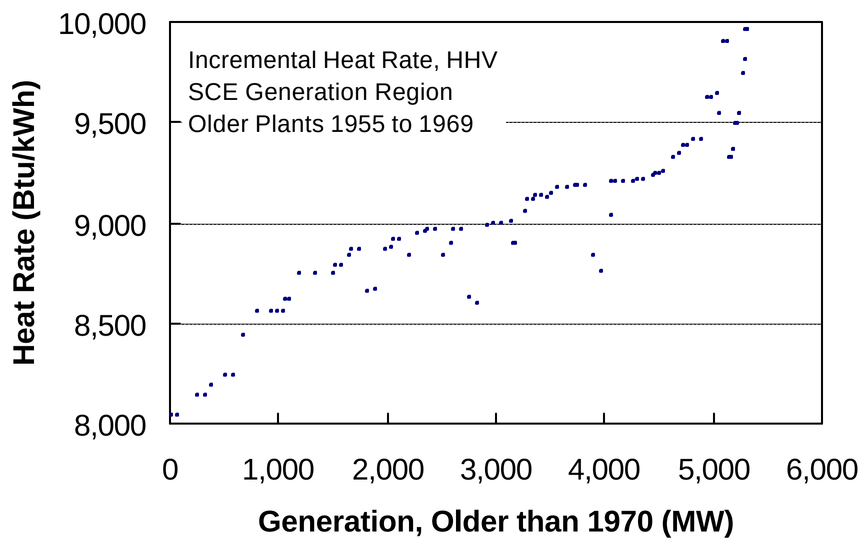
[9] To convert HHV efficiency to LHV efficiency multiply by 103/97. 56.5% x 1.062= 60%.

Figure 4-11: Power Plant Age for SCE generation region



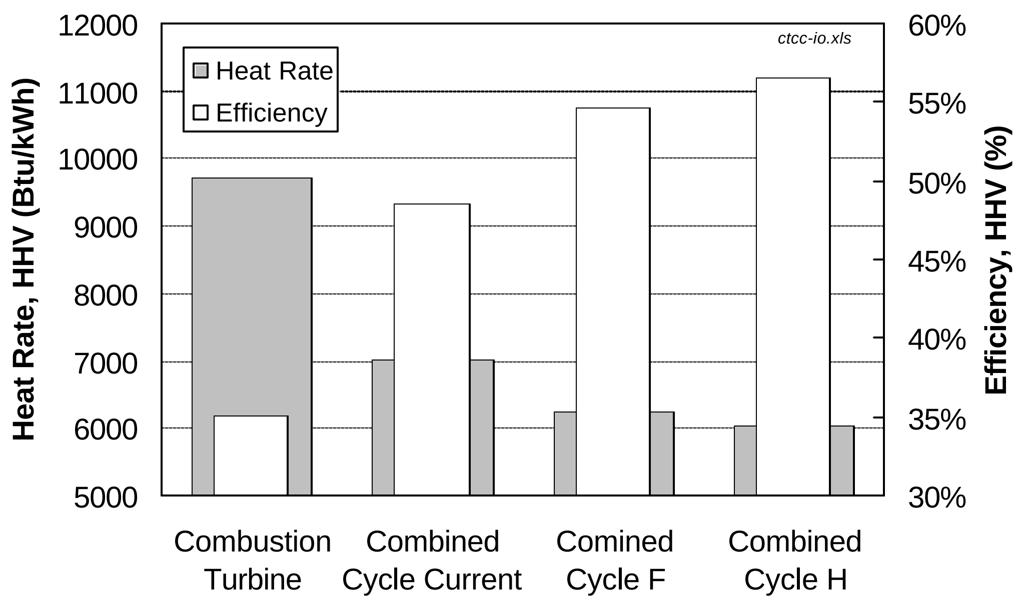
Source: CEC, Multisym Run, April 2001, SCE_Supply.xls

Figure 4-12: Incremental Heat Rates for Older Power Plants in the SCE generation region



Source: CEC, Multisym Run, April 2001, SCE_Supply.xls

Figure 4-13: Energy Consumption and Efficiency of Power Plants



Most of the combustion turbines in new power plants are the F type. Two of the combined cycle power plants planned in California will be equipped with F turbines and have peak efficiencies of 49.4 and 52.3 percent (HHV). Identifying what turbines will be installed in future plants is difficult as the supply of combustion turbines is limited and lead times for delivery are over one year. Lead-time as well as technology risk considerations make the F turbine plants (or plants with similar efficiency) the choice for the new and planned power plants. H type turbines are more efficient but have only recently become available and are not incorporated into planned power plants.

Marginal power generation for EVs may come from the most efficient plants at night. Older natural gas boilers may operate as part of the night time baseload. These plants must operate at night to maintain the thermal energy to provide power on demand in the morning. However, some efficient combined cycle plants may also contribute to the nighttime generation mix.

Baseload plants may operate at relatively low loads. Their efficiency may be as low as 25 percent. Other more efficient combined cycle plants may also operate at night. These plants would operate at much higher efficiency and can be managed according to nighttime loads.

As discussed earlier, hydroelectric, nuclear, and renewables are limited resources. If hydroelectric output increased at night, less hydropower would be available at other times, and it would need to be displaced when the generation system is at peak capacity and all plants are utilized.

4.8.6 Emission Assumptions for EVs

Table 4-27 shows the emission factors for power plants in lb/MWh. The emission factors correspond to the composite for the marginal power generation predicted by the dispatch model in Appendix B. A higher fraction of generation in the SoCAB was assumed for Scenario 2.

Table 4-27: Emission Factors for California Power Plants

Generation Assumptions	NO_x (lb/MWh)	NMOG (lb/MWh)	CO (lb/MWh)	Generation (%)	
				SoCAB	California
Scenario 1	0.59	0.063	1.3	50	20
Scenario 2	0.59	0.063	1.3	50	20
Scenario 3	0.59	0.063	1.3	26	42

Source: CEC, Arthur D. Little.

More important this heat rate is consistent with reserve margins that are predicted in 2010. If these capacity additions do not occur, the heat rate for power generation will be higher and emissions will be affected. The results are affected by the fate of older Rankine cycle facilities that were assumed to be maintained and operated in the future. The disposition of these facilities is largely dependent on power policy in California and was not analyzed further in this study. The analysis reflects dispatching of a generation mix with some newer power plants; however, the inventory of existing generation capacity is in the model assumptions. Also shown in Table 4-27 is the location of marginal power generation, categorized by SoCAB and California excluding the SoCAB. The values for Scenario 3 are based on the 1999 dispatch model results. The estimate of 50 percent is used as an upper bound and based on the 1995 dispatch model results which had a different resource mix assumption.

Table 4-28 shows the estimated marginal power plant emissions for a new gas-fired power plant. NO_x, NMOG, and CO emissions are weighted according to the fraction of generation in the SoCAB. In addition, marginal NO_x from power plants is zero due to RECLAIM constraints. The zero marginal NO_x results does however hinge on the successful use of ERCs for new power plants. Most facilities are currently being phased into RECLAIM but are still subject to Regulation 11 or BACT, until they come into compliance with RECLAIM. Under RECLAIM, there are exemptions for municipal refuse fired facilities that are publicly-owned, landfill gas-fired and energy recovery facilities, and the cities of Burbank, Glendale, and Pasadena. The rest of the

South Coast region will be subject to RECLAIM. Those facilities that are exempt from RECLAIM will still be subject to Regulation 11 rules or BACT.

Table 4-28: Marginal Power Plant Emissions in the SoCAB[a]

	Emissions (g/kWh)		
Scenario	**NO_x**	**NMOG**	**CO**
1	0	0.014	0.30
2	0	0.014	0.30
3	0	0.007	0.15

[a]NO_x, NMOG, and CO weighted according to fraction of in-Basin generation. NO_x emissions are zero due to RECLAIM.

Source: Arthur D. Little.

An important distinction is that the specific generation that corresponds to EV recharging is not so important as the difference between total generation with and without EVs. Some efforts have been made to relate specific generation resources to nighttime generation for EVs. However, matching limited generation resources to EV demand may be a misleading accounting exercise as the net change in total generation resources is most relevant.

4.8.7 Electricity Distribution

Electricity distribution results in losses through the power lines. Typical transmission losses range from 3.5 to 13.5 percent. On hot days, increased loads due to air conditioning high air temperature result in greater heating of the transmission lines and losses up to 16 percent (Levins). This value varies within the transmission system. Transmission losses require additional generation beyond requirements presented in Sections 4.8.2 and 4.8.3. CEC estimated the distribution losses in the 1996 study for LADWP and SCE (around 9% and 7%, respectively). Transmission and distribution losses are largely due to the resistance of the power lines.[10] Losses for nighttime generation were estimated by determining the power and electric current through the distribution system as a function of time of day. The hourly losses were estimated to correspond to an average daily system loss of 8 percent. Distribution losses during the off peak hours assumed for EV charging were 6 percent. Constraints on the transmission system similar to those in 2001 would increase losses; however this effect has not been quantified. Transmission losses have a smaller effect on the results of this study as generation within the SoCAB covers shorter distances than all of the power consumption in the SoCAB.

[10]Electrical resistance losses according to Ohm's law = i^2R while power = Vi. Distribution losses as a fraction of power increase as power increases (i^2R/Vi) as current through the power lines increases.

Losses also occur during vehicle charging. The magnitude of these losses depend on the battery type and charging system. EV energy consumption is reported in terms kWh of electricity at the outlet; therefore, the EV energy consumption includes charging losses. Actual energy consumption could vary with the type of EV charger and the state of battery charge, as discussed in Section 5.

4.9 Fuel Storage and Distribution

Marketing and distribution of fuels involve their storage, transport, and transfer to a vehicle. These steps are described as Phases 4 through 8 in Section 3. The storage and distribution of liquid fuels is similar and considered in Section 4.9.1. Section 4.9.2 considers emissions from gaseous fuels.

4.9.1 Liquid Fuel Storage and Distribution

Diesel, reformulated diesel, LPG, FTD, and methanol will be stored in bulk storage tanks, both at production facilities and at product distribution terminals. Emissions from marketing and distribution of fuels primarily consist of fugitive emissions, such as breathing losses, vapor transfer losses, and spills during fuel transfers.

4.9.1.1 Local Fuel Storage and Delivery — Liquid Fuels

This section describes the bulk storage and delivery of liquid fuels. Table 4-29 shows the emissions from bulk storage tanks based on the calculation technique in AP-42. The throughput is varied for current and future M100.

Table 4-29: Fugitive Hydrocarbon Emissions from Internal Floating Roof Storage Tanks

Fuel	Diesel	FT Diesel	M100	M100
RVP (psi)	0.022	0.030	4.63	4.63
TVP (psi)	0.015	0.02	3.50	3.50
Temperature (°F)	90	90	90	90
MW	130	120	32	32
Tank capacity (bbl)	50,000	50,000	8,000	50,000
Tank diameter (ft)	100	100	45	100
Tank height (ft)	36	36	30	36
Throughput (bbl/yr)	600,000	600,000	100,000	600,000
Throughput (gal/day)	69,041	69,041	11,507	69,041
Turnover (day/tank)	30.42	30.42	29.20	30.42
Emissions (lb/yr)	88	94	718	1,663
Emissions (g/gal)	0.0016	0.0017	0.0776	0.0300

Source: A. D. Little

According to the staff of the SCAQMD refinery and bulk storage inspection and permitting teams, floating roof tanks are the most common storage tank type in the SoCAB. These tanks comply with “Rule 463: Organic Liquid Storage” which regulates the storage of gasoline in above-ground tanks among other compounds. Tanks in bulk storage farms and refinery are often used to store more than one type of product including diesel and other intermediary refinery product. The tanks therefore must comply with the requirement for gasoline storage.

Vapor controls are required to be at least 95% efficient. Internal and external floating roof tanks must be equipped with liquid mounted primary and secondary seals consistent with the best available technology. Other tanks are outfitted with vapor recovery systems that feed the recovered vapor either into an incinerator or a liquefier. For Scenario 3, a 90 percent reduction in emissions (reduction factor of 0.1) is assumed for methanol tanks in the SoCAB. Such controls were not assumed for diesel where its vapor pressure would not result in vapor control requirements.

Current M100 emissions are based on calculations for an 8000-bbl floating roof tank. The throughput includes both chemical and vehicle methanol demand. Future methanol emissions assume the same tank size and throughput as that of diesel as shown in Table 4-30.

Table 4-30: NMOG Emissions from Bulk Fuel Storage

	NMOG Emissions (g/gal)	
Fuel	**Plant/ Refinery**	**Bulk Terminal**
Diesel	0.036	0.0036
LPG	0	0
FT Diesel	0.01[a]	0.0036
M100	0.03[a]	0.003

[a]Facilities outside SoCAB

4.9.1.2 Local Fuel Distribution — Liquid Fuels

This section describes the storage and distribution of liquid fuels at local service stations. These emissions consist of the following categories:

- Tank truck unloading spills
- Under ground tank filling — working losses
- Under ground tank breathing
- Vehicle fuel tank filling — working losses

Fuel is unloaded from a tank truck with vapor recovery (referred to as Stage I). Most liquid fuel in California is stored in underground tanks. During the course of fuel storage, the vapor or ullage space in the tank expands and contracts with as atmospheric pressure changes and fuel temperature changes. The fuel temperature remains almost constant in underground tanks. Fuel is dispensed to vehicles with a vapor recover hose system (Stage II vapor recovery).

The different stages of fuel distribution were observed to provide insight for this project. There are no significant differences in the unloading of gasoline or alcohol fuels. Fuel unloading at service stations is performed by the tank truck operator who may be an oil company employee or work for an independent company. Unloading is accomplished with appropriate precautions for safety and minimizing emissions. Fuel and vapor transfer hoses are connected from the storage tank to the truck. The truck carries its own fuel transfer hoses and an assortment of fittings for connection to the underground tank. After verifying the remaining tank volume with a dipstick measurement, the truck operator initiates the gravity fed unloading operation. When the fuel transfer is completed, the hoses are returned back to the tank truck. There is still a considerable volume of fuel in the fuel transfer hose (about 4-inch inner diameter). The truck operator disconnects the hose from the truck tank and drains the remaining fuel in the bottom of the hose into the underground storage tank by lifting the hose into the air and moving the elevated section towards the connection at the underground tank. The hose is then disconnected and stored on the truck. During several such fueling operations, about 250 ml of fuel was observed spilling out of the hose as it was placed back into its holding tube on the truck. It was estimated that the volume from spills is about 180 g for an 8000 gal fuel load or 0.023 g/gal (0.05 lb/1000 gal). While this quantity is based on casual observations, it provides some quantification of a small source that is not explicitly counted in the inventory. It is difficult to spill no fuel during hose transfers since the inner wall of the transfer hose is covered with fuel as indicated by hooks on some tanker trucks for drying clean up rags. An even smaller amount of fuel may remain on the hose surface and evaporate later.

Truck transfer is intended to be a no spill operation. Drivers are instructed to drain the hose into the tank before placing it back on the truck. Catch drains at the top of underground tanks would capture some spilled fuel if it dripped from the tank connection. However, some wet hose losses are inevitable. The thin layer of fuel in the hose will results in some drips and evaporation. It should be pointed out that the volumes used in this study are based on rough estimates and do not reflect a large sample. Furthermore, liquid spill volumes are difficult to measure. While further quantification of the frequency and quantities of Stage I spillage would be necessary to assure the accuracy of this value, it is significantly smaller than Stage II spillage.

4.9.1.3 Inventory Emission Factors

ARB’s Enhanced Vapor Recovery proposed amendments (February 2000) provide the control factors for gasoline dispensing facilities. The emission sources are broken into the categories shown in Table 4-31. These values are based on ARB’s analysis of the emissions inventory that is consistent with fueling station emission control requirements. Each category has an emission factor for uncontrolled and controlled fueling operations. Spills from tank truck unloading are not explicitly accounted for; however, they may be implicitly included in an adjustment factor. Emissions from working losses and tank breathing are based on a combination of ideal gas law calculations in AP-42 and ARB's certification testing results. ARB's current inventory for 2010 is based on 0.61 lb/1000 gal for non-Stage II systems and 0.42 lb/1000 gal for Stage II equipped systems. These values account for the lower flow rates in the Stage II equipped systems. Fuel flow rate potentially affects the amount of fuel spillage. Diesel fuel that is dispensed without Stage II vapor recovery has very low evaporative emissions. Emission regulations take this into account with the higher factor for Stage II spillage. All of the spilled liquid will evaporate from the concrete surface at service stations. Uncontrolled emissions are determined from the gas concentration in the tank ullage space.

Table 4-31: ARB Emission Control Factors for Gasoline Dispensing Facilities

Description	Control Factor (%) 2000	Control Factor (%) 2010	Inventory Defect Rate (%)	High Defect Rate[a] (%)
Underground tank working loss	95	98	0	0
Underground tank breathing loss[b]	90	90	0	0
Vehicle refueling vapor displacement	95	95	5	7
Vehicle refueling spillage	0	0	0	0

[a] High values for Scenario 2
[b]Gasoline emissions are based on 10% 0.1 oil lb/1000 gal. Breathing emissions for other fuels are proportional to vapor pressure.
[c] Applies to all storage stations by 2005

Since the values in this study will be compared to emission inventories, it is important to understand how those inventories are developed. Emission inventories are based on the mix of controlled and uncontrolled sources and estimate of the number of operations with defective emission controls. Stage I and Stage II vapor recovery are considered to be 98 percent and 95 percent effective respectively; so controlled emissions are 2 percent and 5 percent of the uncontrolled value. Breathing losses from underground tanks are estimated at 10 percent of 0.1 lb/1000 gal emission factor for gasoline and adjusted for methanol and diesel vapor pressures. The mix between controlled and uncontrolled service stations varies across the State. Some smaller operations have been exempt from Stage II vapor recovery requirements. Stage I vapor recovery is always used. In addition to reducing emissions, it returns vapor product to the refinery and provides for safer operations.

Statewide inventories are comprised of emission factors that are adjusted for malfunctions or failures in the vapor recovery system or defect rate. As an example for gasoline, emissions from vehicle refueling vapor displacement or working losses with 95 percent control, and an example 4 percent defect rate would be the following:

$$\text{Refueling losses} = VD \times (1\text{-}DR)(1\text{-}CF) + VD \times DR \quad (4.6)$$

Where:

VD = vapor density
CF = control factor
DR = defective rate

Thus:

$$\text{Refueling losses} = 7.6\ (\text{lb}/1000\ \text{gal}) \text{ x } (1 - 0.04) \text{ x } (1 - 0.95) + 7.6\ (\text{lb}/1000\ \text{gal}) \text{ x } 0.04 = 0.67\ \text{lb}/1000\ \text{bal} \quad (4.7)$$

The defect rate has a profound effect on the overall emission estimate and was incorporated into the vapor emissions in this study. Emission inventories include control factors that vary by year and also defect rates that vary by year. Since these numbers are not readily accessible at this time, distribution emissions were based on the assumptions shown in Table 4-31. The control factors and defect rates were applied to M100. The baseline uncontrolled emissions were then modeled from the fuel's vapor pressure and vapor molecular weight.

Future emissions will be affected by the use of onboard refueling vapor recovery (ORVR) compatible with Stage II recovery systems. The interaction between ORVR and some Stage II systems results in more emissions than when each system is used separately. Gasoline ORVR systems on vehicles may not achieve 95 percent recovery over the life of the vehicle, and a defect rate may be established for ORVR by ARB. There will be defect rates in the ORVR systems based on age and equipment failure, although these have not been quantified. The requirements for M100 vehicles have not been determined at this time; however a higher defect rate was assumed for Scenario 2.

Distribution emissions are estimated from the emission control assumptions in Table 4-31 and the fuel's properties. An underlying assumption is that the control effectiveness is equal for all fuels. There might be greater variation in control effectiveness for small volume fuel distribution (perhaps higher or lower) and underground tank breathing losses would depend upon the fueling station throughput. The number of vehicles per station will vary as more alcohol-fueled vehicles are introduced into the State. A total vehicle to fueling station ratio of about 2500 currently exists for gasoline-fueled vehicles. Many of these stations have multiple tanks. As alcohol-fueled vehicles are introduced, the ratio of vehicles to fuel tanks will approach the ratio for gasoline tanks. Therefore, differences in breathing losses due to differences in throughput will be small on a lb per day basis during an alcohol vehicle transition and would become negligible for a larger fleet of alcohol-fueled vehicles. Second order effects on breathing losses (per gallon) would depend on whether gasoline tanks are decommissioned if alternative-fueled cars displace gasoline-fueled cars. Given equivalent assumptions on emission control, distribution emissions depend on fuel vapor pressure and vapor molecular weight.

4.9.1.4 Vehicle Fueling Spillage

While most vehicle operations are successful with little fuel spilled from the nozzle, occasionally a significant quantity of fuel is spilled. Fuels spills and form vehicle refueling were evaluated by ARB in the Enhanced Vapor Recovery proposed amendments (February 2000). The proposed rulemaking will set standards for spillage, drips, and nozzle retention. These standards are presented in Table 4-32. For calculation purposes, spillage, liquid retention, and nozzle spitting are lumped together on a g/gal basis. All of these emissions are event related. The amount of fuel spilled per event is constant; so, larger fuel tanks or volumes of fuel dispensed result in lower emissions per gallon dispensed. Historically, emission factors for spillage have been 0.7 lb/1000 gal. This value was adjusted downward to 0.42 lb/1000 gal and with new standards for Stage II systems limiting spillage to 0.24 lb/1000 gal. For Stage II systems, spillage plus liquid retention results in 0.40 lb/1000 gal of gasoline.

Table 4-32: Old and Proposed Standard for Gasoline Spillage, Dripping and Nozzle Retention

Source	Old Standard	Units	New Standard	Units	Effective
Phase II dispensing spillage	0.42	lb/1000 gal	0.24	lb/1000 gal	4/1/01
Dripless nozzle	None	—	1	drops/fueling event	4/1/01
Liquid retention	None	—	350	ml/1000 gal	4/1/01
			100[a]	ml/1000 gal	4/1/04
Nozzle spitting	None	—	1	ml/nozzle	4/1/01

Source: ARB

The liquid retention emissions are based on gasoline evaporating from the nozzle. With methanol, this level of evaporation would be lower and virtually eliminated with diesel. The ARB emission factor for diesel spillage is 0.61 lb/1000 gal. The requirement for diesel spillage is higher than that of gasoline for several reasons. Since vapor emissions from diesel are much lower than those from gasoline, a higher spillage rate is allowed in the rules. Since diesel fueling occurs without vapor recovery, higher fueling rates are possible. The potential for spillage is potentially higher with higher fueling rates.

Service station fueling practices were also observed to evaluate vehicle fueling. The dispensers at numerous fuel stations were polled to determine the amount of fuel dispensed per fueling event. The amount of fuel dispensed ranged from one half to 18 gallons with an average of 8 gallons[11]. The volume of fuel dispensed is important in determining emissions that depend on the number of fueling events rather than fuel

[11] Four fueling stations survey in 1996, 12 fueling stations in 1998.

volume. Various vapor recover nozzle types are used at service stations in California. At self-service stations, the vehicle driver dispenses the fuel. Most customers select the lower price self-service option.

In 1994 API published a study that indicated a spillage emission rate of 0.31 lb/1000 gal while the value used in emission inventories was 0.7 lb/1000 gal. An even lower spill emission factor is assumed for new gasoline vehicles with Stage II controls. The lower spill emission rates that are expected to apply by 2010 and are assumed in emission inventories are based on nozzle performance that is consistent with certification requirements.

Spillage rates of other liquid fuels were estimated. The low emission case is shown in Table 4-33 and the higher emission case is shown in Table 4-34. The diesel emission rates are consistent with the 0.61 lb/1000 gal assumed in the inventory. FTD spillage volume is assumed to be the same of that of diesel. Since FTD has a lower density, the g/gal of spillage are slightly lower. Both gasoline and M100 would be subject to Stage II emission controls so the spillage emissions are assumed to be the same per fueling event. Spillage emissions per gallon depend upon refueling volume, which is estimated from vehicle fuel economy to be consistent with the 8 gallons per fill for gasoline vehicles. The average fill volume assumed for gasoline in 8 gallons. An increase in fuel tank capacity is expected for alternative-fueled vehicle.

4.9.1.5 Vapor Space NMOG Mass

Vapor emissions in this study are determined from modeled vapor concentrations. The fuel temperature used to determine vapor concentrations was selected to be consistent with ARB's inventory for fueling station emissions.

Table 4-33: Vehicle Fuel Spillage Parameters: Scenario 3

Fuel	Fill Volume[a] (gal)	Tank Size (gal)	Fuel Economy (mpg)	Volume (NMOG, mL)	Liquid Retention/Spillage (g/gal)
Diesel	8.0	14.5	41.8	2.56	0.277[b]
RFD	8.0	14.5	41.8	2.56	0.277
LPG	11.2	20.4	21.5	2.0	0.090
FTD	8.0	14.5	38.0	2.56	0.249
M100 FC	11.6	21.0	20.9	2.02[c]	0.138
Gasoline	8.0	14.5	30.2	2.02	0.182

[a]Fuel tank size is not reduced for diesel, FTD.
[b]0.61 lb/1000 gal for non-Stage II fueling.
[c]Same spillage volume as gasoline.

Source: Arthur D. Little

Table 4-34: Vehicle Fuel Spillage Parameters: Scenario 2

Fuel	Fill Volume[a] (gal)	Tank Size (gal)	Fuel Economy (mpg)	Spill Volume (NMOG, mL)	Spillage (g/gal)
Diesel	5.8	10.5	41.8	2.56	0.383
RFD	5.8	10.5	41.8	2.56	0.383
LPG	11.2	20.4	21.5	2.0	0.091
FTD	6.4	11.6	38.0	2.56	0.313
M100 FC	11.6	21.0	20.9	2.66	0.182[b]

[a]Fuel tank size reduced with fuel economy.
[b]Emission factor for gasoline fueling.

Source: Arthur D. Little

The vapor concentration in the tank vapor space is the basis for fuel transfer emission calculations in AP-42 and provides insight into the temperature conditions for vapor emissions. Vapor space concentrations are modeled to from equilibrium vapor concentration. The extent of vapor saturation is reflected by the saturation factor. For vapor recovery systems a saturation factor of 1.0 or completely saturated vapor is assumed in AP-42. ARB bases the vapor space concentration on test data. The vapor space gas concentration represents the uncontrolled emissions from tank truck unloading (underground tank working losses), and vehicle tank working losses.

Vapor space concentrations from liquid fuels were estimated from the ideal gas law. Given a molar volume of 379.6 ft^3/lb mole at 60°F, the equilibrium vapor (V_e) in a tank head space can be calculated from the following equation:

$$V_e \text{ (lb/gal)} = \text{MW(lb/mol)} \times \text{lbmol}/379.6 \text{ ft}^3 \times 0.1337 \text{ ft}^3\text{/gal} \times \text{TVP}/14.7 \text{ psi} \times 520°\text{R}/T \qquad (4.8)$$

Where:

T = gas and liquid temperature (°R)
TVP = true vapor pressure (psi) at the equilibrium temperature

Table 4-35 shows the vapor space concentrations from various liquid fuels. Since the ARB inventory is based on test data that represents a range of gas temperatures and actual saturation conditions, a representative condition was modeled that reflects the inventory value. These values are used for Scenario 1 and 3. An effective fuel temperature was estimated. The vapor density for methanol and diesel was calculated from vapor temperatures, the fuel's vapor pressure, and molecular weight of vapors. The molecular weight of reformulated gasoline vapors and 76°F temperature result in a vapor density of 7.6 lb/1000 gal which was the emission factor for uncontrolled gasoline refueling. The effective storage tank temperature of 76°F was used to represent the storage conditions for methanol and diesel vehicles. This approach when applied to the molecular weight of reformulated gasoline vapors is consistent with the new emission factor of 7.6 lb/1000 gal for gasoline vehicle refueling. The same temperature conditions can then be applied to a range of liquid fuels to generate vapor space concentrations or uncontrolled emission estimates that are consistent with California inventories. This effectively results in an equivalent equilibrium temperature that reflects the actual range of fuel temperatures and saturation conditions that correspond to test data. The underlying assumption with this approach is that the inventory data is based on a broad range of conditions and reflects the suitable conditions. Also shown in Table 4-35 are the vapor densities vary with temperature.

Table 4-35: Evaporative Emissions from Local Fuel Distribution

Fuel/ Emission Category	RVP	Effective Temperature (°F)	Uncontrolled NMOG Vapor Mass (g/gal)	(lb/1000gal)	Controlled NMOG Vapor (g/gal) [a] w. Control	& Defect
ARB vehicle working loss	— [b]	76	3.45	7.6	0.173	0.2053
Consistent with Invcentory, Scenarios 1 and 3 [c]						
Diesel UG tank working loss	0.022	70	0.009	0.02	0.009	0.009
Diesel UG tank breathing loss	0.022	70	0.0009	0.002	0.001	0.001
Diesel vehicle working loss	0.022	76	0.011	0.02	0.011	0.011
FTD UG tank working loss	0.03	70	0.012	0.03	0.012	0.012
FTD UG tank breathing loss	0.03	70	0.0012	0.003	0.001	0.001
FTD vehicle working loss	0.03	76	0.014	0.03	0.014	0.014
M100 UG tank working loss	4.5	70	0.68	1.5	0.014	0.014
M100 UG tank breathing loss	4.5	70	0.07	0.1	0.007	0.007
M100 vehicle working loss	4.5	76	0.79	1.7	0.040	0.077
Worst Case, Scenario 2 [d]						
Diesel UG tank working loss	0.022	76	0.011	0.02	0.011	0.011
Diesel UG tank breathing loss	0.022	70	0.0009	0.002	0.001	0.001
Diesel vehicle working loss	0.022	90	0.017	0.04	0.017	0.017
FTD UG tank working loss	0.03	76	0.014	0.03	0.014	0.014
FTD UG tank breathing loss	0.03	70	0.0012	0.003	0.001	0.001
FTD vehicle working loss	0.03	90	0.021	0.05	0.021	0.021
M100 UG tank working loss	4.5	76	0.79	1.7	0.016	0.016
M100 UG tank breathing loss	4.5	70	0.068	0.1	0.007	0.007
M100 vehicle working loss	4.5	90	1.15	2.5	0.080	0.155

[a]Tank working loss control factor = 98%, Vehicle working loss control factor = 95%.
[b]Based on an RVP of 7 psi.
[c]No vapor controls for diesel. M100 working loss defect rate is 5%.
[d]No vapor controls for diesel. M100 working loss defect rate assumed to be 7%.

Vapor concentration (uncontrolled NMOG vapor mass) for this study was determined from equilibrium vapor densities that correspond to 70°F for underground tank vapors, and 76°F for vehicle fuel tank vapors. Actual vehicle vapor temperatures can be higher. The effect of higher vapor temperatures is also shown in Table 4-35. These values are used for Scenario 2.

Table 4-35 also shows tank truck distribution emissions for liquid fuels. These emissions take into account vapor recovery effectiveness and a 5 percent defect rate for Stage II emission controls. A 7 percent defect rate is used for Scenario 2. The higher defect rate reflects the potential interaction between ORVR equipment and vapor control equipment or simply a less effective vapor recovery system. These values used in Scenario 2 are more pessimistic than those used in the inventory. Since no methanol powered fuel cell vehicles or any passenger cars that operate on M100 are built in commercial volumes, emission control requirements can still be developed. Such emission control requirements would address Stage II efficiency requirements, refueling connections that reduce the risk of misfueling, ORVR requirements, and other details of refueling.

4.9.2 LPG Distribution

LPG is stored and distributed in pressurized tanks. The fuel is stored in a liquid state at ambient temperature and the pressure in the tank is in equilibrium. At 70°F the storage pressure is 105 psig. When LPG is transferred from a storage tank to a tank truck, or to a vehicle fuel tank, a transfer pump provides about 50 psi of differential pressure. When fueling vehicle tanks, the fuel enters the tank and the LPG ullage condenses. This process can be accelerated with top loaded tanks where the liquid spray can absorb some of the heat from condensing the vapors.

The tank trucks are filled at refineries with a two hose system with one hose acting as a vapor return. Hoses are evacuated after fuel transfer operations at the refinery. Tank trucks can be filled to a safe fraction of its water capacity by weighing the truck during fueling (Lowi 1994), although this is not the current practice. However, current regulations require the use of an "outage" valve that indicates when the tank is full. Some LPG also enters the atmosphere from the fuel transfer fitting.

Table 4-36 shows the emissions associated with LPG storage and distribution. The LPG emissions correspond to the volume of liquid that escapes from the fuel transfer fitting divided by the amount of fuel transferred. Currently, LPG vehicles in California are equipped with an “outage” valve that indicates the 80 percent fill level by spilling LPG to the atmosphere. During vehicle fueling, the outage valve is opened and vapors pass through a 0.060-inch orifice and through the valve. When LPG reaches the 80 percent level in the vehicle tank, liquid enters the fill level line and exits into the atmosphere. A puff of white liquid is visible to the fueler that provides an additional signal that the tank is full. California's vehicle code requires use of the outage valve. As indicated in Table 4-36, emissions from vehicle fueling are several grams per gallon.

Table 4-36: Fuel from LPG Fuel Delivery

Emission Source	Tank Volume (gal)	Liquid Spill Volume (ml/fill)	Liquid Spill Volume (ml/gal)	Spill Rate (g/gal)
Transfer tank outage[a]	10,000	—	—	1
Bulk tank outage	30,000	—	—	0.2-0.5
Truck fill outage[a]	—	—	—	2
Truck fill hose	3,000	1,391	0.139	0.070
Local tank hose	1,000	17.4	0.0017	0.0008
Local tank outage[a]	—	—	—	5
Vehicle tank outage	—	—	—	0

[a]Better vapor management could eliminate this emissions source by the year 2010.

Many LPG tanks are already equipped with automatic stop-fill devices that could eliminate fuel tank vapor venting; however, Titles 8 and 13 of the California Administrative Code require the use of the outage valve. Other countries, including the Netherlands where many LPG vehicles operate, do not use the outage valve for fueling. One might expect that many LPG vehicles in California are fueled without using the outage valve if they are equipped with automatic stop fill devices.

A committee of NFPA, CHP, NPGA, and WLPGA representatives are working to set standards that will allow LPG vehicles to be fueled without leaking LPG to the atmosphere. Equipment that will minimize the fuel released from transfer fittings is also being approved (Wheeler 1994). EPA regulations on evaporative emissions from vehicles will also eliminate vehicle outage valve emissions.

Emission estimates for LPG fueling are based on the following conditions:

- 1391 cc loss from fuel couplings on 10,000 gal delivery trucks. Fluid loss is equivalent to 18 in of 1.25-in (inner diameter) hose (Lowi 1992)

- Current vehicle hose coupling liquid losses are 7.57 cc (Lowi 1992) for a 12 gallon fuel transfer. Dry-break couplings would have less than 5 percent of the trapped volume of current LPG nozzles of the same capacity. The use of these nozzles is expected beyond the year 2000.

- Current fuel tank vapor displacement is based on sonic flow through a 1.5 mm orifice, 70°F tank temperature with a fuel pressure of 105 psig. Assuming an orifice discharge coefficient of 0.5 results in 2 g/s of vapor flow. With an 8 gal/min flow rate, vapor displacement is 15 g/gal.

- Vapor displacement from current tank truck filling assumes a 100 gal/min fill rate with an outage loss of 2 g/s.

4.9.3 Natural Gas Transmission and Distribution

Natural gas is transported through pipelines with compressors that maintain a pressure ranging from 220 to 1100 psi. A typical distribution pressure is 800 psi. Marginal gas will be transported from West Texas or Western Canada.

The compressor power, distance, and gas throughput for several pipeline projects was summarized by AGA (AGA 1993). The average energy use is 0.014 hp/MMscf/d. Compression energy represented on a per mile basis ranged from 0.6 to 2 hp-hr/MMscf/mi with a weighted average of 0.9 hp-hr/MMscf/mi for Western States. Emissions from compressors are based on emission rates and transportation distances in Section 4.1. The emissions database calculates emissions in g/1000 mi/100scf. Compression energy usage is calculated in terms of a percentage of 1000 mi transported.

4.10 Toxic Emissions

This study analyzes the toxic emissions that are associated with fuel production and distribution in California urban areas. These toxic emissions correspond to marginal fuel cycle emission assumptions. Accordingly, the primary source of toxics are associated with tanker truck and rail car distribution, power generation, additional energy consumption related to clean diesel production, and vehicle fueling losses. Sources that are not expected to contribute to marginal emissions in California include average refinery emissions, methanol, FTD, and gas processing plant emissions (which occur outside of California) and coal power plants. Similarly, this study does not evaluate the effect of alternative fuel use on reduced tanker ship traffic and the potential for accidental releases. LFG and biomass based ethanol plants could generally result in a reduction in toxic emissions depending on the source of waste feedstocks. The numerous feedstock alternatives are not evaluated here. An example is presented in a study on ethanol production (Perez 2001). Using feedstocks such as agricultural residue which would otherwise be burned results in a significant reduction in particulate emissions and potentially a reduction in toxics also.

California Assembly Bill AB 1807 created a comprehensive program to address adverse public health impacts from emissions of toxic substances to ambient air. Toxic air contaminants are an air pollutant that may cause or contribute to an increase in mortality or an increase in serious illness. A series of compounds were identified by ARB as toxic air contaminants, five of which are related to the combustion of fuels. They are 1,3-butadiene, benzene, formaldehyde, acetaldehyde, and diesel particulates. In addition, there are several compounds that are precursors to toxic air contaminates. Polycyclic aromatic hydrocarbons (PAH) and nitro-PAH are such precursors. Data on toxics were obtained from emission studies that include speciation data as well as the SoCAB inventory of toxics which are documented by source category and presented in Appendix A of Volume 2.

Combustion compounds in diesel exhaust that are PAH and nitro-PAH are given in Table 4-37.

Table 4-37: Polycyclic Aromatic Hydrocarbons (PAH) and Nitro-PAH Found in Diesel Exhaust

PAH	Nitro-PAH
2,3,5-trimethylnaphthalene	1-nitronaphthalene
phenanthrene	2-nitronaphthalene
anthracene	methylnitronaphthalenes
me-phenanthrenes/anthracenes	2-nitrophenyl
fluoranthene	4-nitrophenyl
pyrene	5-nitroacenaphthalene
benzo[c]phenanthrene	2-nitrofluorene
benzo[ghi]fluoranthene	9-nitroanthracene
cyclopenta[cd]pyrene	1-nitropyrene
benz[a]anthracene	3-nitrofluoranthene
chrysene + triphenylene	4-nitropyrene
benzo[b+j+k]fluoranthene	7-nitrobenz[a]anthracene
benzo[e]pyrene	6-nitrochrysene
benzo[a]pyrene	6-nitrobenzo[a]pyrene
perylene	
indeno[1,2,3-cd]fluoranthene	
benzo[c]chrysene	
dibenz[a,j]anthracene	
indeno[1,2,3-cd]pyrene	
dibenz[a,h+a,c]anthracene	
benzo[b] chrysene	
benzo[ghi]pyrene	
coronene	
dibenzo[a,l]pyrene	
dibenzo[a,e]pyrene	
dibenzo[a,I]pyrene	
dibenzo[a,h]pyrene	

Toxic emissions and toxic precursors were estimated for diesel engine exhaust, diesel fuel, diesel fuel vapor, natural gas, liquid petroleum gas, refinery emissions, pipeline compression engine emissions, and power plant emissions. They are given in terms of milligrams of toxics per gram of NMOG in Table 4-38. Discussion of the findings can be found in the following subsections.

Diesel Exhaust

Table 4-38: Toxic and Precursor Emissions Levels

	Function (mg/g NMOG)					
Sources	**Benzene**	**1,3- Butadiene**	**Formaldehyde**	**Acetaldehyde**	**PAHs**	**N-PAHs**
Diesel exhaust[a]	17.78	5.44	130	42.0	1.67	0.01
Diesel fuel, low aromatic[b]	0	0	0	0	9.36	ND
Diesel vapor, low aromatic[b]	0	0	0	0	9.36	ND
LPG from natural gas	0	0	0	0	0	0
LPG from petroleum	0	0	0	0	0	0
Refinery combustion[a]	ND	ND	124	ND	ND	ND
Power plant emissions[d]	ND	ND	844	ND	ND	ND
Natural gas IC engine exhaust[b]	2.98	1.19	130	3.0	0	0

[a]MATES data, SCAQMD 2000
[b]ARB speciation database, ARB 1993

4.10.1.1 Diesel Fuel and Vapor

Diesel exhaust has been a subject of recent interest due to the fact that diesel particulates have been identified as a toxic air contaminant. In a recent study by CE-CERT for ARB diesel exhaust was speciated. Some earlier studies also speciated diesel exhaust, but not to the level given in the CECERT study (CE-CERT). In this report, diesel exhaust was measured from a Cummins L-10 engine using three diesel fuels including California low-aromatic diesel fuel. The results are shown in Table 4-39. The ratio of toxics to NMOG in Table 4-39 provides the data for Table 4-38.

Table 4-39: Diesel Exhaust Emissions

Component	Emissions (mg/bhp-hr)	Mass Fraction (mg/g NMOG)
THC	470	—
Methane	19	35
1,3 Butadiene	2.46	5.4
Benzene	8.03	17.8
Formaldehyde	58.8	130
Acetaldehyde	19.1	42
PAHs	0.752	1.7
Nitro-PAHs	0.004	0.01
Particulate	183	—

Source: CE-CERT

Diesel fuel was analyzed and speciated in a report done by California Institute of Technology and Oregon State University entitled “Characterization and Control of Organic Compounds Emitted from Air Pollution Sources,” Final Report, ARB Contract number 93-329, April 1998. In this report, diesel fuel was shown to have no toxic air contaminants. PAHs were measured, but nitro-PAHs were not. Data for

PAHs in diesel fuel are shown in Table 4-39. Since no data can be found on diesel fuel vapor, it is assumed that the levels of PAHs and other TACs are the same as in the fuel itself.

4.10.1.2 LPG and Natural Gas

Natural gas and by-product LPG contain standard hydrocarbons, which is consistent with the long-term geological origin of the fuel. Refinery-based LPG contains such as propene LPG analyses are generally not performed to the same detail as gasoline speciations. However, since both LPG and natural gas are lower hydrocarbon gases, ND toxic air contaminants or precursors should be present.

4.10.1.3 Refinery Emissions

The petroleum refining industry converts crude oil into more than 2500 refined products, including LPG, gasoline, kerosene, aviation fuel, diesel fuel, fuel oils, lubricating oils and feedstocks for the petroleum industry. AP-42 gives emission factors for hydrocarbons and aldehydes for the various processes of petroleum refining. These data provide an estimate of the ratio of aldehydes to HC. These are given in Table 4-40 for the various refinery processes. Over 99 percent of the hydrocarbons coming from a refinery are non-methane. While only total aldehyde emissions are given, it is assumed that the majority is formaldehyde. More detailed data on petroleum refineries are included in the SoCAB inventory in Appendix A which are summarized in Table 4-38.

Table 4-40: Controlled Refinery Emissions in lb/1000 ft^3 of Gas

Process	HC	Aldehydes
Fluid catalytic cracking	0	0
Moving-bed catalytic crackers	87	12
Fluid cooking beds	0	0
Compressors	21.8	1.61
Vapor recovery systems	0.8	0
Vacuum distillation	0	0

4.10.1.4 Power Plant Emissions

Emission factors for the generation of electricity using large controlled gas turbines are also given in AP-42. It is assumed that all power plant gas turbines in the South Coast use selective catalytic reduction with water injection as the emission control device. Emission factors from AP-42 are given in Table 4-41.

Table 4-41: Emission Factors for Large Controlled Gas Turbines in lb/MMBtu Fuel Input

Compound	lb/MMbtu
NMHC	0.0032
Formaldehyde	0.0027

4.10.1.5 Natural Gas IC Engine Exhaust

Natural gas-fired internal combustion engines are used in the natural gas industry at pipeline compressor and storage stations. These engines provide power to drive the compressors. At pipeline compressor stations, the engine is used to move natural gas from station to station. It is assumed that all pipeline engines in the South Coast are controlled. While AP-42 gives emission factors for these type of engines, better speciated exhaust emissions for natural gas IC engines can be found from Phase 2 of the Auto/Oil Air Quality Improvement Research Program. In this program, three CNG vehicles were tested on four different natural gas fuels. Both engine out and tailpipe were measured. Since pipeline engines are controlled in the South Coast but not to the level found in CNG vehicles, the engine out and tailpipe emission levels from the Auto/Oil program were ratioed at 25 percent/75 percent respectively. This gave emission factors for benzene that were close the AP-42 values. Engine-out and tailpipe emission factors from the Auto/Oil program are given in Table 4-42.

Table 4-42: Weight Percent of Total Hydrocarbon Emissions for CNG Vehicles

	Engine	Tailpipe
1,3-Butadiene	0.046	0.001
Benzene	0.072	0.016
Formaldehyde	3.867	0.434
Acetaldehyde	0.234	0.0435
Methane	78.937	93.734

5. Fuel Economy

Fuel-cycle emissions, including CO_2, correspond largely to the total volume of fuel produced. As such, fuel consumption is a strong driver in determining total fuel-cycle emissions. In general, as more fuel is produced, more feedstocks are extracted and transported, production facilities operate with greater throughput, and trucks and pipelines move more fuel to fueling stations. This section reviews the data inputs used in this study, methods for estimating fuel economy, and the sets of fuel economy assumptions that were used for the fuel-cycle analysis.

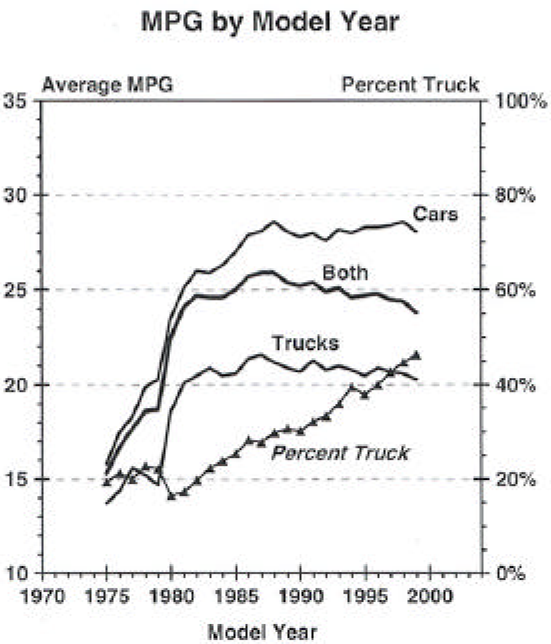
5.1 Fuel Economy Data and Projections

Fuel economy estimates for alternative fuel technologies were derived from comparisons of existing vehicles and model estimates. These comparisons were made for vehicles that are close to identical except for fuel. A consistent set of fuel economy estimates was determined by investigating the ratio of energy economy (mi/Btu) for alternative vehicles to comparable gasoline vehicles. These energy economy ratios (EERs) were then applied to a single baseline gasoline fuel economy. While gasoline fuel cycle emissions are not a part of this study, the baseline gasoline fuel economy provides a reference point for estimating alternative vehicle fuel economy.

The U.S. EPA reports fuel economy for all certified vehicles. The U.S. EPA Fuel Economy Guides were used to determine fuel economy for current vehicles. Limited production alternative fuel vehicles are also certified and listed in the Fuel Economy Guide. Advanced technologies, such as fuel cells are at the prototype stage, but some tests and model predictions have been made relative to their fuel economy. These sources have been used to predict fuel economy for vehicles produced in 2010.

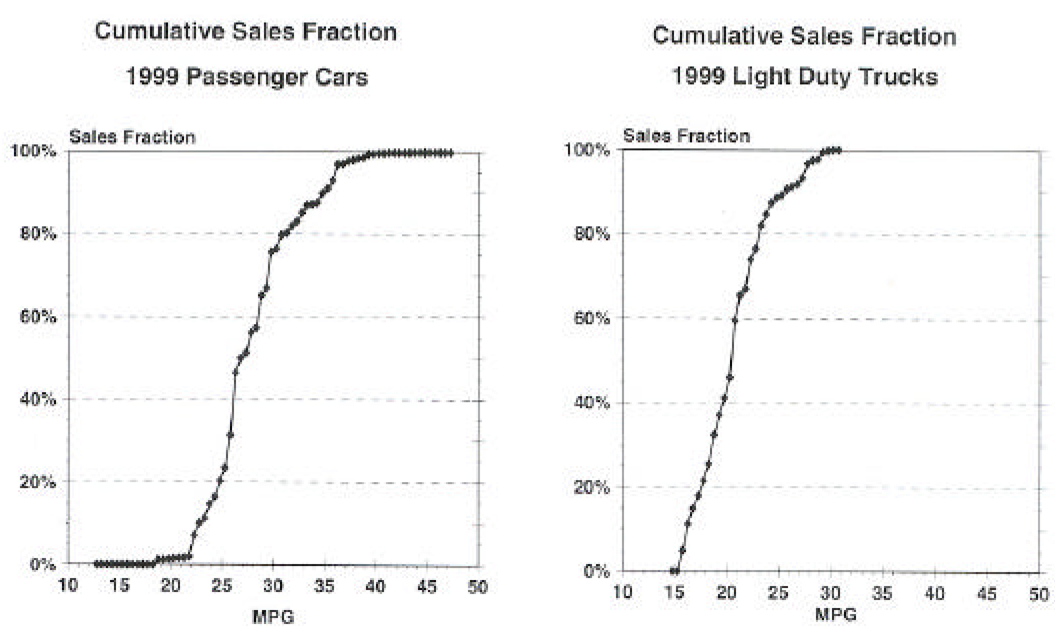
According to the U.S. EPA, after a surge in average fuel economy during the late 70's and gradual increases during the 1980's, average fuel economy has been on the decline. Though per-vehicle fuel economy has remained steady or only slightly decreased, the market shift to heavier SUVs and light trucks in the 1990's has brought the overall average down about 2.1 mpg to 25.9 mpg (Heavenrich). Figure 5-1 shows the U.S. EPA's estimate of average fuel economy trends for the past 25 years. One might expect a continued gradual decline with no changes to CAFE or the fuel prices. The U.S. EPA's report also shows the variation between models sold in 1999. As shown in Figure 5-2, most passenger cars are estimated to achieve between 22 and 36 mpg, with a small percentage achieving more or less than this range. Similarly, over 80% of light trucks achieve between 15 and 23 miles per gallon, with most of the rest achieving up to 32 mpg. This sales fraction data is useful in determining the possible shifts in fuel economy trends.

Figure 5-1: Fuel Economy Trends, 1999



Source: Heavenrich, 1999.

Figure 5-2: Sales Fractions of 1999 Passenger Cars and Light-Duty Trucks by Fuel Economy



Source: Heavenrich, 1999.

The comparison of fuel cycle emissions is intended to represent a significant volume of vehicles that could be certified as PZEVs. These PZEV vehicles could displace battery ZEVs so the types of vehicles represented in this study are intended to be a consistent type of vehicle. These comparisons would then represent vehicles in similar classes and performance capabilities. This is not necessarily straightforward, as various vehicles have different attributes that are particular to the technology and are not be replicated in another vehicle technology. This issue will be discussed further in the following subsections.

5.2 Estimating the Fuel Economy of the Alternative-Fueled Vehicle

To compare the fuel cycle of a new alternative vehicle to the conventional vehicle it replaced, it is important to know the fuel economy of both. However, determining the fuel economy of the replaced vehicle is no small task, and it can be estimated in two ways. First, the replaced vehicle could simply be the average vehicle in the entire fleet. Alternatively, one could use the fuel economy of the *class or size* of the replaced vehicle as the baseline. The second method provides a better "apples to apples" comparison and is used in this study.

5.2.1 Baseline Gasoline Vehicles

Gasoline vehicle fuel economy is estimated in order to provide a basis for determining a consistent set of assumptions for the fuels considered in this study. Baseline fuel economy was determined for one class of vehicles, namely subcompacts. Subcompacts represent one of the most fuel-efficient classes of vehicles and many of the advanced technology vehicles are in this class. Sixty-eight model year 2000 vehicles within this class were averaged (high performance vehicles were eliminated from the data – see Volume 2, Appendix D for the list of vehicles). Using undiscounted fuel economies[12] the average fuel economy for the 68 vehicles was 32.2 miles per gallon. To account for real world conditions, this certification fuel economy should be discounted by about 15 percent resulting in an on-road fuel economy of 27.4 mpg[13]. Assuming a 10% improvement in fuel economy between 2000 and 2010, the average baseline fuel economy is 30.16 mpg. The purpose of the subcompact baseline is to establish baseline fuel economy from which methanol, diesel, LPG, and EV fuel economy can be projected. Alternative fueled vehicles are compared with conventional gasoline vehicles to project fuel economy. Light-weight hybrid electric or future gasoline fuel cell vehicles can achieve higher fuel economy than the subcompact vehicles presented here; however gasoline vehicle fuel cycle emissions are not analyzed in this study.

[12] The EPA Fuel Economy Guide lists discounted fuel economy results to account for real world driving. Undiscounted values are published at EPA's Fuel Economy website (www.fueleconomy.gov). Undiscounted values provide a better comparison among various alternative technologies and fuels.

[13] EPA's adjustment for on-road driving is City FE x 0.9 and Highway FE x 0.82.

Table 5-1 shows the EERs for baseline gasoline, diesel, LPG, methanol fuel cell, and electric vehicles. The approach for determining EERs, and future vehicle trends, was extensively reviewed by a technical advisory committee (TAC) including state agencies, carmakers, and fuel providers. These EER results are also being used in a CEC study of energy efficiency. These values are used to determine fuel economy for different vehicle/fuel configurations. The following discussion identifies basis for the EER values.

Table 5-1: Energy Economy Ratios for EER Fuel Cycle Analyses

	2000		2010		
Technology/Fuel	**EER**	**Weight Ratio**	**EER High**	**EER Low**	**Weight Ratio**
Gasoline, RFG ICE	1.00	1.00	1.00	1.00	1.00
Diesel, FTD DI CI	1.37	1.02	1.37	1.21	1.02
LPG ICE	—	—	1.08	0.98	1.05
Methanol SR/PEMFC	—	—	1.54	1.39	1.50
Battery EV	2.85	1.29	2.90	2.40	1.25

Source: A. D. Little, Volume 2

The EER values for diesel and LPG vehicles represent conventional (non-hybrid) designs. Future diesel and LPG EERs have not been reviewed by the TAC; however, the high EERs may be expected to be greater by a factor of about 1.2 for hybrid designs. Such vehicles may be available in the same time frame as methanol fuel cell vehicles.

5.2.2 Diesel Vehicles

Only Volkswagen currently produces light-duty diesel vehicles in the United States. Three models of diesel vehicles were compared against their gasoline counterpart, namely the Golf, Jetta, and New Beetle. Using a lower heating value for diesel fuel of 130,800 Btu/gallon, the average fuel economies for the model year 2000 automatic transmission versions of these vehicles were compared, resulted in an EER of 1.37 as shown in Table 5-2. Weight comparisons showed the diesel vehicles to be about 2 percent heavier than their gasoline counterparts. Note that gasoline equivalent mpeg calculations are based on indolene certification fuel with a lower heating value of 114,500 Btu/gal, which is the test fuel for EPA fuel economy tests.

Table 5-2: Diesel Energy Economy Ratio

Model	Diesel Version mpg	Gasoline Equivalent mpeg	Gasoline Version mpg	EER
New Beetle	44.7	39.1	28.5	1.37
Golf	44.7	39.1	28.5	1.37
Jetta	44.7	39.1	28.5	1.37

In a separate analysis, CEC examined 176 European direct-injected diesel vehicles and compared them against 831 European gasoline vehicles of the same class. This resulted in an EER of 1.21. Thus the range of EERs for future diesel vehicles was assumed to be 1.21 to 1.37. The EER values in Table 5-2 are somewhat higher than what might be expected from a diesel engine alone. Tradeoffs in fuel economy, engine size, and acceleration capability account for the relatively high fuel economy of the diesel models. The vehicles in Table 5-2 may not represent ideal "apples-to-apples" comparisons; however the fuel economy reflects actual vehicle performance.

5.2.3 LPG Vehicles

Fuel economy for LPG vehicles was estimated from existing CNG vehicle data. No EPA certification data was available for existing identical LPG and baseline gasoline vehicles. An EER range of 0.98 to 1.08 was estimated for CNG and CPG vehicles. The higher octane number and potential for lean-burn operation favors CNG vehicles. LPG has an octane number greater than gasoline but lower than CNG and a lower weight fuel system.

5.2.4 Fuel Cell Vehicles

Prototype hydrogen fuel cell vehicles built by Ford and Daimler-Chrysler have been tested on U.S. driving cycles, but have no direct gasoline equivalent. Steam reformed methanol vehicles and autothermal reformer gasoline fuel cells are being tested in the laboratory. Several academic institutions have developed computer models of fuel cell vehicles to predict fuel economy for these technologies. Using this limited modeling and vehicle data, EERs of 1.50 to 1.74 have been estimated for hydrogen fuel cell vehicles, 1.39 to 1.54 for methanol steam reformed fuel cell vehicles, and 0.97 to 1.35 for gasoline POX reformed fuel cell vehicles. These estimates are highly speculative and will need to be refined as these technologies become more commercial. The TAC provided significant input and the fuel economy of fuel cell vehicles. Carmaker comments indicated that EERs above 2.0 for hydrogen fuel cell vehicles did not reflect identical gasoline and hydrogen vehicles. Appendix D provides a summary of the simulation modeling results from several studies and hydrogen FCV performance data.

5.2.5 Electric Vehicles

Several models of electric vehicles are currently in production both in the passenger car and light truck classes. Only the light truck and minivan classes have gasoline equivalent vehicles of the identical models. The passenger car electric vehicles are specialty built vehicles with no direct gasoline comparison. Furthermore, the Federal test procedure for certifying electric vehicles tends to provide biases in regards to battery technology. While the average EER for the vehicles shown in Table 5-3 is 2.7, an EER range between 2.4 and 2.9 was estimated as a representative comparison of equivalent 2010 electric vehicle and gasoline technology. Many EER comparisons shown in Appendix D fall outside this range. Current nickel metal hydride (NiMH) battery powered vehicle comparison tend to have low EERs. During charging, some

NiMH vehicles use "active cooling" to remove the heat that is generated during charging. Active cooling approaches include operating the vehicle's air conditioner, which uses power that is counted as part of the vehicles energy consumption. Future EVs will avoid charging that requires such high parasitic loads. Several of the vehicle combinations resulted in EERs over 3. In particular comparisons of the GM EV1 with conventional cars indicate very high EERs. However, the EV1's energy consumption is partly due to weight reductions, low drag coefficient, and low rolling resistance tires. Therefore, existing gasoline vehicles compared with the EV1 result in a higher EER comparison than would be achieved with more comparable vehicles.

Table 5-3: Electric Vehicle Energy Economy Ratios

Electric Vehicle			Gasoline Vehicle		
Model	FE kWh/mi	FE (mpeg)	Model	FE (mpg)	EER
2000 Ford Ranger – PbA	0.405	82.7	2000 Ford Ranger	25.5	3.24
2000 Ford Ranger – NiMH	0.421	79.5	2000 Ford Ranger	25.5	3.12
1999 Chrysler EPIC – NiMH	0.696	48.1	1999 Dodge Minivan	25.9	1.86
1998 Chevy S10 – PbA	0.431	77.7	1998 Chevy S10	25.3	3.07
1998 Chevy S10 – NiMH	0.546	61.3	1998 Chevy S10	25.3	2.43
1999 Honda EV Plus – NiMH	0.499	67.1	1999 Honda Civic/Accord	32.7	2.05
1999 GM EV-1 – NiMH	0.321	104.4	1999 Geo Metro - Auto - 1.3L	37.6	2.78
1999 GM EV-1 – PbA	0.280	119.6	1999 Geo Metro - Auto - 1.3L	37.6	3.18

5.2.6 High Efficiency Vehicles

Vehicles such as the VW diesel Lupo (Birch) and the EV1 can be categorized as high efficiency designs. Weight reductions and low drag coefficients result in fuel economy improvements that apply to both gasoline and alternative vehicle drive trains. A category of high efficiency vehicles was also analyzed. This class is similar to the concept for the Partnership for New Generation of Vehicles (PNGV). Baseline light-weight gasoline cars were estimated to be 50 percent more efficient than typical subcompacts, resulting in a baseline gasoline fuel economy of 45.2 mpg. This value is consistent with PNGV assessments of fuel economy.

5.3 Fuel Economy Classes

The U.S. EPA has also performed estimates of potential improvement upon the baseline fuel economy for conventional cars by using a "best-in-class" methodology. Essentially, this methodology assumes that all vehicles of a certain class would achieve the same fuel economy of the best car in that class, and then recomputes an average over the entire fleet. For this study, the shift in the new average (about a few mpg for both passenger cars and light trucks) was used to estimate the potential *nominal* improvement over the baseline. As described below, the more aggressive scenario assumes that this potential shift is doubled.

DOE projected estimates for several different vehicle types, sizes and timeframes. This data is particularly useful as it closely matches the methodology used in this study (described below). The ratio shown in Table 5-4 is the estimated improvement in fuel economy of each of these technologies as compared to a gasoline baseline (see Section 5.4). The DOE information is generic for fuel cell vehicles reflecting a mix of methanol and hydrogen vehicles. This study uses estimates for methanol vehicles with steam reformers that will be less efficient than hydrogen fueled vehicles.

Table 5-4: Projected Ratio of Improvement in Fuel Economy (EER)[a] by Vehicle Type and Technology

Technology	Small Car	Large Car	Minivan	Sport Utility Vehicle	Pickup and Large Van
Electric	4	N/A[b]	4	4	N/A
Advanced Diesel	1.35	1.35	1.45	1.45	1.35
Fuel Cell	N/A	2.1	2.1	2.1	N/A

[a]EER = energy economy ratio
[b]N/A = not analyzed unlikely vehicle market

Source: DOE 1999

DOE data uses a vehicle choice analysis that includes a number of factors, including vehicle availability, size, purchase cost, fuel price, fuel economy, range, expected maintenance costs, truck space, acceleration, and top speed in conjunction with a vehicle choice analysis. The vehicle choice analysis simulates the preference of buyers to purchase vehicles that maximize their utility and uses current market research data to inform what these choices are. In this way, the model provides output that shows the expected penetration of each vehicle type over time. EPA's data provides breakouts of sales fraction by size class, so in combination, we can estimate the sales of vehicles *by technology and size class for 2010*, if we assume that sales fractions by size stay the same. This estimate is shown in Table 5-5. The results are shown for a variety of fuel options because the DOE study identifies vehicle stock for the entire fleet. These results are affected by modeling assumptions such as fuel price. The purpose of examining market share for this study is to assess which gasoline vehicles would potentially be replaced by alternative fuel choices.

Table 5-5: Estimated Vehicle Sales in California in 2010 by Size Class and Technology Type

	2010 Sales Population	RFG	Diesel, FTD	HEV (RFG)	LPG or CNG	PEMFC (M100)	PEMFC (RFG, Naphtha)	PEM FC (H_2)	Alcohol FFV	Electric
Cars										
Small	267,300	106,920	85,536	61,479	—	—	—	—	—	13,365
Medium	233,200	93,280	74,624	53,636	—	—	—	—	—	11,660
Large	88,000	42,328	9,680	19,360	1,760	2,904	2,904	2,904	6,160	—
Minivans										
Small	—	—	—	—	—	—	—	—	—	—
Medium	100,100	87,087	9,009	—	1,001	—	—	—	2,002	1,001
Large	13,200	11,484	1,188	—	132	—	—	—	264	132
SUVs										
Small	22,000	15,180	4,400	—	880	—	—	—	—	1,540
Medium	128,700	88,803	25,740	—	5,148	—	—	—	—	9,009
Large	68,200	47,058	13,640	—	2,728	—	—	—	—	4,774
Pickup Trucks										
Small	17,600	11,616	3,168	—	704	—	—	—	2,112	—
Medium	55,000	36,300	9,900	—	2,200	—	—	—	6,600	—
Large	106,700	70,422	19,206	—	4,268	—	—	—	12,804	—
Total	1,100,000	610,478	256,091	134,475	18,821	2,904	2,904	2,904	29,942	41,481
	100.0%	55.5%	23.3%	12.2%	1.7%	0.3%	0.3%	0.3%	2.7%	3.8%

Source: DOE OTT, 1999

The vehicle stock mix data in Table 5-5 is combined with information in the next subsection to determine the fuel economy of the replaced vehicle (either as a fleet average or as an average of a certain subsegment of the market).

5.4 Estimating the Fuel Economy of the Replaced Vehicle

Table 5-6 shows fuel economy assumptions for each size class of conventional vehicle. To obtain the baseline fuel economy for the analyses, we started with fuel economy estimates from EPA (U.S. EPA 1999) for the baseline MY (Model Year). The "Baseline" column indicates the laboratory fuel economy of each class provided by EPA, with a downward adjustment of 15% to account for real-world conditions. The "Nominal" fuel economy improvement in the next two columns is based upon the EPA's best-in-class (BIC) methodology, described above. The final two columns — the "Aggressive" fuel economy improvement — assume *twice the nominal* improvement (which could reflect the possibility of increased fuel prices driving demand for better fuel economy).

Table 5-6: Fuel Economy Estimates for the Replaced Vehicle, Fleet Average

	Baseline	Nominal Improvement		Aggressive Improvement	
	1999 Actual FE Replaced RFG Vehicle	BIC % Improvement	2010 BIC mpg Actual Average — Replaced RFG Vehicle	2 x BIC % Improvement	2010 BIC mpg Actual Average — Replaced RFG Vehicle
Cars					
Small	26.0	12.8%	29.3	25.6%	32.7
Medium	23.1	12.8%	26.1	25.6%	29.0
Large	20.7	12.8%	23.3	25.6%	25.9
Minivans					
Small	—	8.8%	—	17.6%	—
Medium	19.3	8.8%	21.0	17.6%	22.7
Large	15.1	8.8%	16.5	17.6%	17.8
SUVs					
Small	21.1	8.8%	22.9	17.6%	24.8
Medium	17.7	8.8%	19.2	17.6%	20.8
Large	14.2	8.8%	15.4	17.6%	16.7
Pickup Trucks					
Small	20.8	8.8%	22.7	17.6%	24.5
Medium	19.9	8.8%	21.6	17.6%	23.4
Large	15.6	8.8%	16.9	17.6%	18.3
Weighted Average	**21.0**		**23.4**		**25.7**

BIC = best in class

The weighted average in Table 5-7 is the vehicle sales fraction-weighted fuel economy for the *entire fleet*. Thus, this number was calculated by combining information from Table 5-5 and the “Nominal” values in Table 5-6. To determine the fuel economy of a conventional vehicle that is replaced by a *specific technology*, the same calculations were performed using only the sales fractions for that technology. Table 5-8 below shows how the DOE market share results imply a fuel economy for the replaced gasoline vehicle.

For example, an average diesel vehicle will replace an average gasoline vehicle with a fuel economy of 24.6 mpg. This means that diesel vehicles, on average (as estimated by DOE), will penetrate more of the small car segments that get higher fuel efficiency. Conversely, CNG vehicles are expected to replace lower-fuel economy, heavier vehicles. Here, the replaced conventional gasoline vehicle only achieves 19.2 mpg. For the purposes of this study, we assumed that FTD vehicles were interchangeable with diesel vehicles with retard to market share. Similarly, LPG vehicles were assumed to be interchangeable with CNG vehicles. While the results in Table 5-7 depend on the results of DOE’s choice model, they indicate how the replaced gasoline vehicle could be different for different fuel options. ARB’s criteria for low fuel cycle emission for the PZEV allowance is based on NMOG emissions below 0.01 g/mi. This criteria is easier to meet with high fuel economy vehicles.

Table 5-7: Fuel Economy of Alternative Vehicle by Technology/Fuel Type and Replaced Vehicle Fuel Economy Assumption

Vehicle Type	Vehicle Size	mpg 1975	mpg 1999	mpg Increase	Percent Increase
Cars	Small	18.3	30.6	12.3	67.2
	Midsize	13.6	27.2	13.6	100.0
	Large	13.1	24.3	11.2	85.5
Wagons	Small	22.4	32.2	9.8	43.8
	Midsize	13.2	26.1	12.9	97.7
	Large	11.9	—	—	—
Vans	Small	20.6	—	—	—
	Midsize	13.3	22.7	9.4	70.7
	Large	12.6	17.8	5.2	41.3
SUV	Small	16.1	24.8	8.7	54.0
	Midsize	12.1	20.8	8.7	71.9
	Large	12.2	16.7	4.5	36.9
Pickup	Small	22.5	24.5	2.0	8.9
	Midsize	21.1	23.4	2.3	10.9
	Large	13.1	18.3	5.2	39.7

Table 5-8: Fuel Economy of Replaced Conventional Gasoline Vehicle for Specific Technology Comparisons

	Gasoline, RFG	Diesel, FTD	HEV (RFG)	LPG or CNG	PEMFC (M100)	Alcohol FFV	Electric
Weighted Average	22.3	24.6	27.2	19.2	23.3	19.9	24.1

5.5 Estimating the Fuel Economy of the Alternative Vehicle

Using the EERs from Table 5-1 and the average gasoline fuel economy of 27.4 mpg for current vehicles, 30.2 mpg for 2010 gasoline subcompact vehicles, and 45.2 mpg for 2010 gasoline light-weight vehicles, the fuel economies shown in Table 5-4 are calculated. Five fuel economy cases are defined below:

- Case a – Current vehicles and current EERs
- Case b – 2010 subcompact vehicles using 2010 low EER estimates
- Case c – 2010 subcompact vehicles using 2010 high EER estimates
- Case d – 2010 light-weight vehicles using 2010 low EER estimates
- Case e – 2010 light-weight vehicles using 2010 high EER estimates

Table 5-9 shows five different sets of assumptions about alternative vehicles' fuel economies. Set "a" results from the baseline fuel economy data for 1996. Sets "b" and "c" utilize nominal fuel economy improvements for the replaced vehicle. Sets "d" and "e" utilize aggressive fuel economy improvements for light-weight, high efficiency vehicles. Sets "b" and "d" are similar in that they use a low EER for each technology/fuel type, while "c" and "e" use a high EER.

Table 5-9: Fuel Economy Cases Used in Fuel Cycle Analyses

Fuel)	Vehicle	Case	LHV (Btu/gal)	EER	Fuel Economy
Gasoline	Conventional ICE	a	114,244	1.00	27.42 mi/gal
Diesel	IDI CI	a	130,800	1.37	43.01 mi/gal
LPG	Conventional ICE	a	83,200	0.98	19.57 mi/gal
Electric	Battery EV	a	3,412[a]	2.85	2.33 mi/kWh
Gasoline	Conventional ICE	b	114,244	1.00	30.16 mi/gal
Diesel	IDI CI	b	130,800	1.21	41.79 mi/gal
RFD	IDI CI	b	128,900	1.37	41.64 mi/gal
FT Diesel	IDI CI	b	118,800	1.21	37.95 mi/gal
LPG	Conventional ICE	b	83,200	0.98	21.53 mi/gal
Methanol	SR/PEM Fuel Cell	b	57,000	1.39	20.92 mi/gal
Electric	Battery EV	b	3,412[a]	2.40	2.16 mi/kWh
Gasoline	Conventional ICE	c	114,244	1.00	30.16 mi/gal
Diesel	IDI CI	c	130,800	1.37	47.31 mi/gal
RFD	IDI CI	c	128,900	1.37	47.15 mi/gal
FT Diesel	IDI CI	c	118,800	1.37	42.97 mi/gal
LPG	Conventional ICE	c	83,200	1.08	23.72 mi/gal
Methanol	SR/PEM Fuel Cell	c	57,000	1.54	23.18 mi/gal
Electric	Battery EV	c	3,412[a]	2.90	2.61 mi/kWh
Gasoline	Conventional ICE	d	114,244	1.00	45.24 mi/gal
Diesel	IDI CI	d	130,800	1.21	62.68 mi/gal
RFD	IDI CI	d	128,900	1.37	62.46 mi/gal
FT Diesel	IDI CI	d	118,800	1.21	56.93 mi/gal
LPG	Conventional ICE	d	83,200	0.98	32.29 mi/gal
Methanol	SR/PEM Fuel Cell	d	57,000	1.39	31.38 mi/gal
Electric	Battery EV	d	3,412[a]	2.40	3.24 mi/kWh
Gasoline	Conventional ICE	e	114,244	1.00	45.24 mi/gal
Diesel	IDI CI	e	130,800	1.37	70.97 mi/gal
RFD	IDI CI	e	128,900	1.37	70.72 mi/gal
FT Diesel	IDI CI	e	118,800	1.37	64.46 mi/gal
LPG	Conventional ICE	e	83,200	1.08	35.59 mi/gal
Methanol	SR/PEM Fuel Cell	e	57,000	1.54	34.76 mi/gal
Electric	Battery EV	e	3,412[a]	2.90	3.92 mi/kWh

[a]per kWh

Baseline fuel economy projections considered subcompact vehicles. The relative difference in vehicle efficiency for different fuels was estimated to be constant for both subcompact and light-weight vehicles. For example, if an LPG car and comparably sized gasoline car were both found to consume 3000 kJ/km, then LPG vehicles were assumed to have the same relative fuel economy benefit (or disbenefit) for other vehicle size classes. The EER would remain constant. While this assumption is a broad simplification, it is unlikely that sufficient data exists across all vehicle classes to discern specific changes in efficiency for both technology/fuels and sizes.

5.6 Fuel Economy Cases

To put all of this information into a coherent framework, a set of cases to study in the fuel-cycle model was developed. The cases incorporate various sets of assumptions about the replaced vehicle fuel economy and the EERs for each technology/fuel.

- Scenario 1a is the baseline case for 1996. It will use fuel-cycle Scenario 1 with fuel economy assumption set "a" for subcompact vehicles.

- Scenario 2b and 3c explores the *nominally-improved* fuel economy assumption sets "b" and "c" in combination with fuel-cycle Scenarios 2 and 3. The fleet average subcompact is assumed for the replaced vehicle.

- Scenario 3.2e examines the *aggressively-improved* fuel economy assumption "e" in combination with fuel-cycle Scenario 3. Light-weight vehicles with smaller fuel tanks are estimated to have somewhat higher spillage emissions consistent with Scenario 2 assumptions.

Table 5-10: Cases for Comparing Fuel-Cycle Energy Impacts

	Cases for Comparison	**Range of Fuel Cycle, Fuel Economy Assumptions**
1996.	Baseline subcompact	Scenario 1a
2010.	Subcompact, range of fuel economy and fuel cycle assumptions	Scenario 2b, 3c
2010.	Light-weight vehicles with high efficiency. High spillage due to smaller tank size	Scenario 3.2e
2010.	Subcompact emissions in SoCAB and CA	Scenario 3cCA

6. Emission Calculations

Fuel-cycle emissions per unit of fuel were calculated for the fuel and feedstock combinations discussion in Section 3. This study presents fuel-cycle criteria pollutant emissions and fuel-cycle plus vehicle CO_2 emissions. Vehicle exhaust, other than CO_2 and evaporative emissions are not included. These emissions are not within the scope of this study and are part of a complex set of regulatory assumptions. Estimates of vehicle emissions are generally not strongly linked to fuel consumption and can be found in other references. ARB analyzed the on-road exhaust and evaporative emissions for various classes of passenger cars (ARB 2000).

Results are shown here for the year 2010 corresponding to Scenarios 2 and 3. The results for SoCAB plus California emissions and for 1996 are included in Volume 2, Appendix E. The results were organized according to fuel economy cases presented in Section 5.

Table 6-1 shows the marginal NMOG emissions for Scenario 2 on a g/gal basis (per kWh for electric power). These emissions represent the values for the different fuel production and distribution phases discussed in Section 3. Many of the emission sources were estimated to be zero on a marginal basis. Crude oil extraction and transport emissions would not change with additional diesel or LPG usage. It is assumed that additional finished fuel is transported to the SoCAB to represent the marginal fuel input to refineries. In the case of diesel, the mix of refinery operations would be adjusted to accommodate an increase in diesel production. Such a switch is typically performed on a larger scale in the winter for some refineries when they produce more home heating oil and less gasoline. Marginal feedstock transport and fuel production emissions in the SoCAB are zero for methanol and FTD production from remote natural gas. When landfill gas is converted to methanol, additional emissions would be produced from the methanol plant but net emissions from the landfill would be reduced or zero. The NMOG emissions for LPG transport are much higher than those for other fuels. These emissions correspond to the outage value losses from distribution storage tanks, tank trucks, and local fueling stations. This source was assumed to be controlled in Scenario 3. Emissions from methanol from biomass residue produced in California and LPG from natural gas are presented in Volume 2, Appendix E. The primary emission impact between these production routes and overseas oil or methanol is rail transport into the SoCAB.

Table 6-2 shows the marginal emission estimates for Scenario 3. In this scenario, additional emission controls were assumed. The most significant emission reduction assumptions were reductions in spillage emissions per ARB's new rules for enhanced vapor recovery. Methanol vehicles were assumed to experience the same spillage of gasoline vehicles on a gram per fill basis. This scenario takes into account the use of larger diesel vehicle fuel tanks to extend range and reduce spillage emissions. A range of emission reductions was assumed in the LPG infrastructure. All of the outage valve losses from bulk storage, retail, and tank trucks were eliminated.

Table 6-1: Marginal NMOG Emissions in SoCAB per Unit Fuel: Scenario 2

	NMOG Emissions (g/gal)						g/kWh
Fuel-Cycle Process	**Diesel**	**RFD**	**LPG**	**FTD**	**M100 NG**	**M100 LFG**	**Electric**
Feedstock transport	0.0025	0.0025	0.0000	0.0000	0.0000	0.0000	0.0007
Refinery	0.0000	0.0438	0.0000	0.0000	0.0000	-0.3000	0.0140
Fuel transport	0.0000	0.0000	0.0018	0.0020	0.0020	0.0000	0.0000
Fuel unloading	0.0055	0.0055	0.5000	0.0070	0.0080	0.000	0.0000
Bulk terminal	0.0036	0.0036	0.0017	0.0036	0.0063	0.0063	0.0000
Truck loading	0.0110	0.0110	2.0780	0.0140	0.0160	0.0160	0.000
Truck spillage	0.0200	0.0200	0.0008	0.0200	0.0200	0.0200	0.0000
Truck exhaust	0.0020	0.0020	0.0048	0.0018	0.0019	0.0019	0.0000
Truck unloading	0.0110	0.0110	5.0000	0.0140	0.0160	0.0160	0.0000
Storage tank breathing	0.0010	0.0010	0.0000	0.0010	0.0070	0.0070	0.0000
Vehicle working loss	0.017	0.017	0.080	0.021	0.155	0.155	0.000
Spillage	0.383	0.383	0.091	0.313	0.182	0.182	0.000
Total	**0.457**	**0.500**	**7.758**	**0.397**	**0.414**	**0.104**	**0.015**

Table 6-2: Marginal NMOG Emissions in SoCAB per unit fuel: Scenario 3

	NMOG Emissions (g/gal)						g/kWh
Fuel-Cycle Process	**Diesel**	**RFD**	**LPG**	**FTD**	**M100 NG**	**M100 LFG**	**Electric**
Feedstock transport	0.002	0.002	0.000	0.000	0.000	0.000	0.0005
Refinery	0.000	0.0219	0.000	0.000	0.000	-0.300	0.0070
Fuel transport	0.0000	0.0000	0.0018	0.0020	0.0020	0.0000	0.000
Fuel unloading	0.0045	0.0045	0.2000	0.0060	0.0070	0.0000	0.000
Bulk terminal	0.0014	0.0014	0.0007	0.0014	0.0030	0.0030	0.000
Truck loading	0.0090	0.0090	0.0780	0.0120	0.0140	0.0140	0.000
Truck spillage	0.0080	0.0080	0.0003	0.0080	0.0080	0.0080	0.000
Truck exhaust	0.002	0.002	0.001	0.002	0.002	0.002	0.000
Truck unloading	0.0090	0.0090	0.0200	0.0120	0.0140	0.0140	0.000
Storage tank breathing	0.0010	0.0010	0.0000	0.0010	0.0070	0.0070	0.000
Vehicle working loss	0.011	0.011	0.080	0.014	0.077	0.077	0.000
Spillage	0.277	0.277	0.090	0.249	0.138	0.138	0.000
Total	**0.325**	**0.347**	**0.472**	**0.307**	**0.272**	**-0.037**	**0.008**

Tables 6-3 and 6-4 show the emissions for Scenarios 2 and 3 on a g/mi basis. Fuel economy assumptions b and c were applied to g/gal values. The results are also shown in Figures 6-1 and 6-2. These g/mi representations straddle the high and low estimates for 2010 subcompact cars.

Table 6-3: NMOG Emissions per Mile Driven: Scenario 2b

Fuel-Cycle Process	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Fuel economy (mi/gal)	41.8	41.6	21.5	38.0	20.9	20.9	2.16 mi/kWh
Feedstock transport	0.00006	0.00006	0.00000	0.00000	0.00000	0.00000	0.00034
Refinery	0.00000	0.00105	0.00000	0.00000	0.00000	-0.01434	0.00648
Fuel transport	0.00000	0.00000	0.00012	0.00005	0.00010	0.00000	0.00000
Ship/truck loading	0.00039	0.00040	0.11974	0.00055	0.00115	0.00076	0.00000
Bulk terminal	0.00009	0.00009	0.00008	0.00009	0.00030	0.00030	0.0000
Truck spillage	0.00048	0.00048	0.00004	0.00053	0.00096	0.00096	0.0000
Truck exhaust	0.00005	0.00005	0.00022	0.00005	0.00009	0.00009	0.0000
Truck unloading	0.00026	0.00026	0.23223	0.00037	0.00076	0.00076	0.0000
Storage tank breathing	0.00002	0.00002	0.00000	0.00003	0.00033	0.00033	0.0000
Vehicle working loss	0.00041	0.00041	0.00372	0.00055	0.00741	0.00741	0.0000
Spillage	0.00916	0.00920	0.00423	0.00825	0.00870	0.00870	0.0000
Total	**0.01093**	**0.01202**	**0.36038**	**0.01047**	**0.01980**	**0.00498**	**0.00683**

Table 6-4: NMOG Emissions per Mile Driven: Scenario 3c

Fuel-Cycle Process	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Fuel economy (mi/gal)	47.3	47.2	23.7	34.5	23.2	23.2	2.61 mi/kWh
Feedstock transport	0.00005	0.00005	0.00000	0.00000	0.00000	0.00000	0.00019
Refinery	0.00000	0.00046	0.00000	0.00000	0.00000	-0.01294	0.0027
Fuel transport	0.00000	0.00000	0.00008	0.00006	0.00009	0.00000	0.0000
Ship/truck loading	0.00029	0.00029	0.01172	0.00052	0.00091	0.00060	0.00000
Bulk terminal	0.00003	0.00003	0.00003	0.00004	0.00013	0.00013	0.0000
Truck spillage	0.00017	0.00017	0.00001	0.00023	0.00035	0.00035	0.0000
Truck exhaust	0.00004	0.00004	0.00006	0.00005	0.00008	0.00008	0.0000
Truck unloading	0.00019	0.00019	0.00084	0.00035	0.00060	0.00060	0.0000
Storage tank breathing	0.00002	0.00002	0.00000	0.00003	0.00030	0.00030	0.0000
Vehicle working loss	0.00023	0.00023	0.0034	0.0004	0.0033	0.0033	0.0000
Spillage	0.0059	0.0059	0.0038	0.0072	0.0060	0.0060	0.0000
Total	**0.00688**	**0.00737**	**0.01991**	**0.00892**	**0.01173**	**-0.00160**	**0.00287**

Figure 6-1: Marginal NMOG Emissions in the SoCAB: Scenario 2c

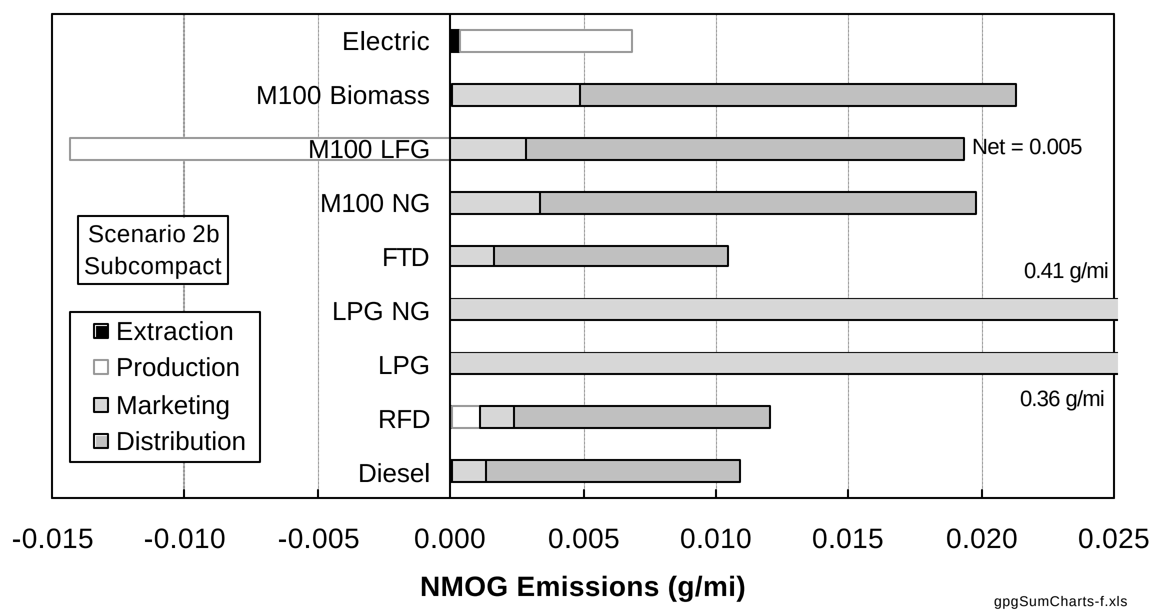
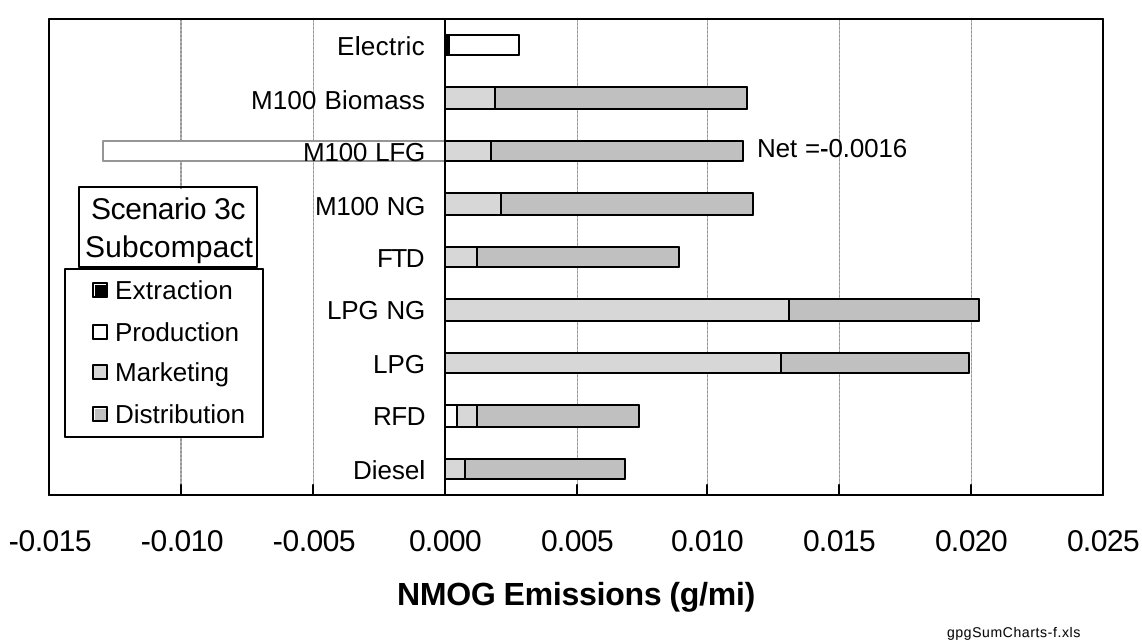


Figure 6-2: Marginal NMOG Emissions in the SoCAB: Scenario 3c



EV emissions are relatively low due to the marginal generation coming from natural gas power plants. In addition, much of the power is generated outside the SoCAB. For Scenario 2, 25 percent of the power is generated in the SoCAB (based on CEC's modeling results). This result is highly dependent on available power plants and reserve margin and warrants further investigation.

For the fuel economy and emission assumptions for Scenario 2b[14], none of the liquid fuel options is below the 0.01 g/mi NMOG level that would qualify as low fuel cycle emissions. An exception is methanol from LFG produced in the SoCAB, where the methanol production facility would have lower NMOG emissions than flaring LFG. The opportunity for these types of facilities seems limited. M100 emissions are high because of the assumptions on refueling vapor recovery, defect rate related to ORVR, and spillage emissions. The assumptions for scenario 2 are more conservative than those in the inventory and represent a worst case. LPG emissions in Scenario 2 reflect outage valve losses from several steps in the distribution process. Regulations that limit these vapor losses are not in place. Spillage assumptions for Scenario 2 were also conservative for diesel and reflect a smaller than gasoline vehicle fuel tank to achieve 350 miles of range.

For Scenario 3c, the diesel vehicle options fall below 0.01 g/mi NMOG. The principal reason for the reduction in emissions over Scenario 2b is the assumption that diesel cars with have slightly larger fuel tanks and greater range than gasoline vehicles. Methanol powered fuel cell vehicles still emit over 0.01 g/mi for Scenario 3c. These total emissions are somewhat higher than estimated in earlier draft reports for this study. Comments received from ARB indicated that refueling emissions would not benefit from ORVR systems. Consequently, 95 percent vapor control combined with a 5 percent defect rate results in working loss emissions of 0.003 g/mi. These emissions combined with spillage emissions are 0.01 g/mi. The balance of bulk storage and tanker ship emissions result in NMOG over 0.01 g/mi for an efficient subcompact car. However, it is likely that fuel cell vehicles might include more design attributes to improve fuel economy. This situation is analyzed under Scenario 3.2e. Fuel cycle NMOG emissions from LPG vehicles are above 0.01 g/mi primarily due to outage valve emissions from LPG bulk storage facilities. Tank truck, transfer truck, and fueling station storage emissions of over 2 g/gal were assumed to be eliminated, although no specific regulations would eliminate these sources. Electric vehicle emissions are lower for Scenario 3c because the vehicle energy consumption is lower (EER corresponding to 2.9) and a smaller fraction of the power is generated in the SoCAB.

Figure 6-3 shows the emissions for light-weight high efficiency vehicles, Scenario 3.2e. This scenario is appropriate for comparison because it is consistent with inventory assumptions on vehicle refueling and is based on highly efficient vehicles that may be built in the future. Spillage assumptions were adjusted to the worst case, as smaller

[14]The letter b designates the fuel economy assumptions

more efficient vehicles are likely to have somewhat smaller fuel tanks. With smaller fuel tanks the amount of fuel per fill is reduced and spillage per gallon increases. Under this Scenario, methanol and diesel fuel options are below 0.01 g/mi NMOG. LPG vehicles are still above 0.01 g/mi, however. Many steps in the LPG distribution chain would need to eliminate outage losses in order achieve the emission levels in Scenario 3. LPG fuel economy could be higher for hybrid designs; however, a careful quantification of actual LPG infrastructure improvements would be needed to consider this fuel in the low fuel cycle emission category.

Figure 6-3: Marginal Fuel-Cycle NMOG Emissions — Scenario 3.2e

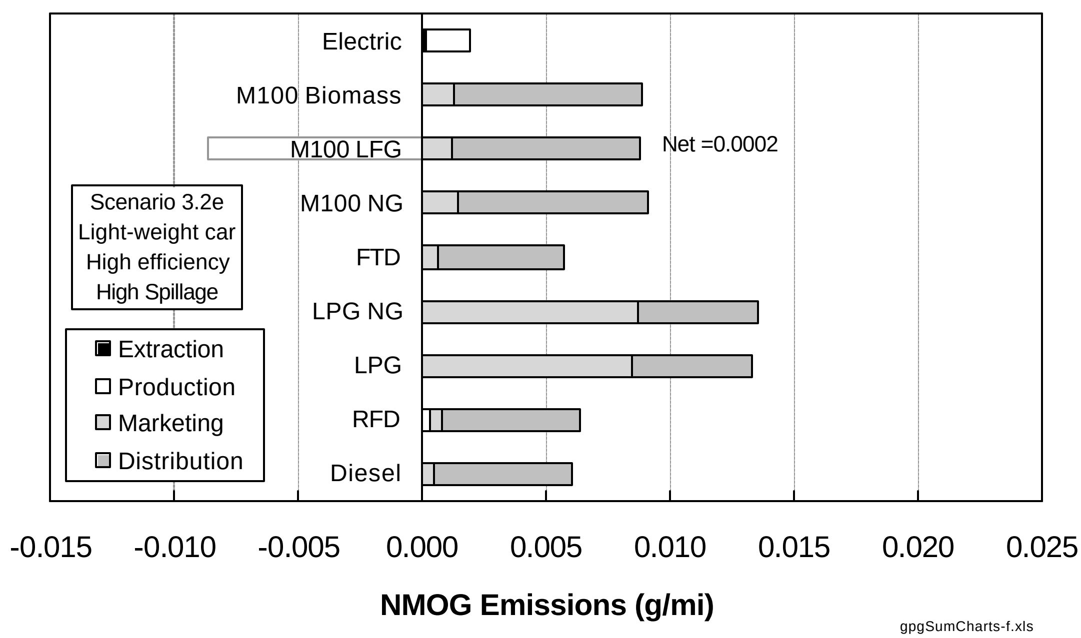


Figure 6-4 shows the NMOG emissions in the SoCAB and California for the subcompact car case. These results include additional rail emissions for LPG produced from natural gas, as the rail car transport would include regions in California east of the SoCAB. Marginal power plant emissions also increase as 80 percent of the power is generated within the State. M100 produced from waste biomass would likely result in near net zero emissions as the alternative paths for using biomass such as agricultural residue also result in emissions.

Figure 6-4: Marginal Fuel-Cycle NMOG Emissions in the SoCAB and California Scenario 3cCA

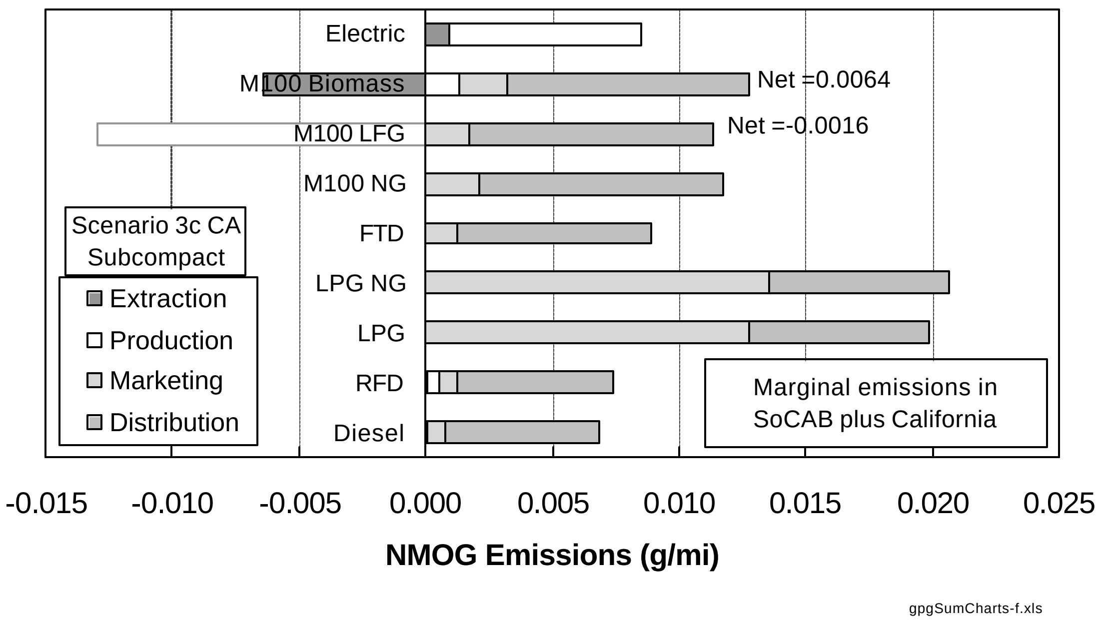


Table 6-5 and Figure 6-5 show the marginal NO_x for Scenario 2b, which corresponds to the high range of emission estimates for subcompacts. As these values are uniformly low, the lower estimates for Scenario 3 are not shown. NO_x emissions are higher for LPG transport as the fuel is transported into the SoCAB by railcar. Marginal NO_x from power generation is counted as zero since this pollutant is capped under the RECLAIM program.

Table 6-5: Marginal NOx Emissions per Unit Fuel: Scenario 2

	NO_x (g/gal)						g/kWh
	Diesel	**RFD**	**LPG**	**FTD**	**M100 NG**	**M100 LFG**	**Electric**
Feedstock transport	0.029	0.029	0.0000	0.0000	0.0000	0.0000	0.0007
Refinery	0.0000	0.0000	0.0000	0.0000	0.0000	-0.01	0.0000
Fuel transport	0.0000	0.0000	0.0207	0.0263	0.0237	0.0000	0.0000
Truck exhaust	0.0494	0.0494	0.1167	0.0438	0.0449	0.0449	0.0000
Total	0.078	0.078	0.137	0.070	0.069	0.035	0.001

Figure 6-5; Marginal NOx Emissions in the SoCAB: Scenario 2b

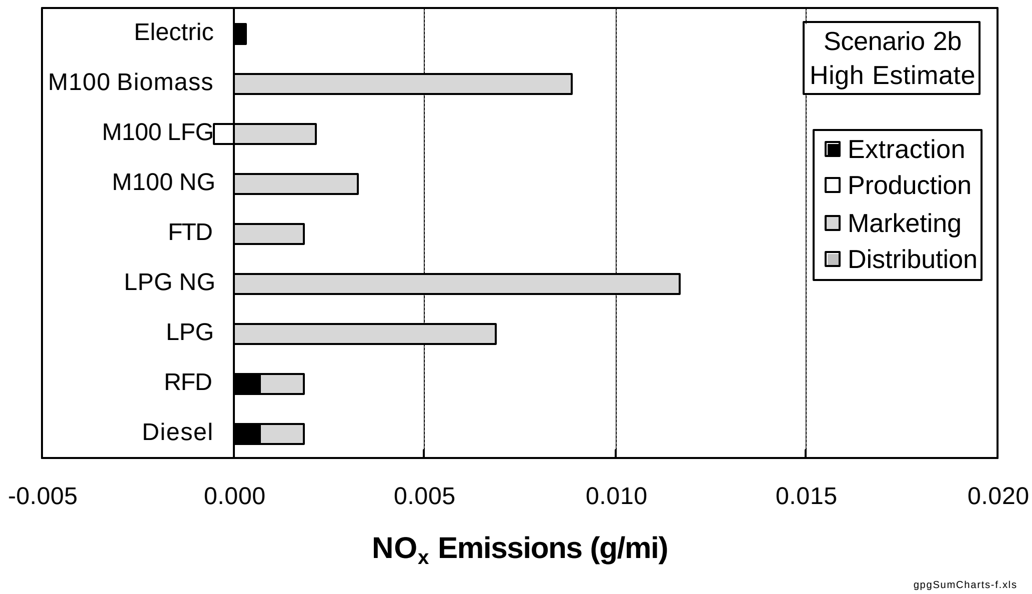


Table 6-6 shows toxic emissions for marginal emission assumptions in the SoCAB. The toxic components for each source were summed with the emission sources in Table 6-1. The values are shown on a g/gal and g/mi basis (using fuel economy assumption b). The most notable emissions are toxics from diesel combustion and formaldehyde from power plants. Diesel particulate is also a toxic air contaminant was counted as part of the total toxic emissions. Detail on diesel particulate emissions are presented in Appendix E.

Table 6-6: Toxic Emissions in the SoCAB: Scenario 2b

Toxics (mg/mi)	Diesel	RFD	LPG	FTD	M100 NG	M100 LFG	Electric
Benzene	0.0017	0.0017	0.0024	0.0020	0.0030	-0.0005	0.0127
Carbon Chlorides	0.0000	0.0000	0.0000	0.0000	0.0000	-0.0140	0.0000
1,3 Butadiene	0.0005	0.0005	0.0024	0.0006	0.0009	0.0004	0.0003
Formaldehyde	0.0017	0.0124	0.0178	0.0146	0.0219	0.0104	0.0551
Acetaldehyde	0.0040	0.0040	0.0058	0.0047	0.0071	0.0034	0.0010
PAHs	0.0636	0.0638	0.0002	0.0002	0.0003	0.0001	0.0000
Diesel Particulate	0.0001	0.0001	0.0001	0.0001	0.0002	0.0001	0.00[a]
Total	0.072	0.083	0.029	0.022	0.033	0.000	0.069

[a]Power plant PM is not diesel PM and not counted in this category.

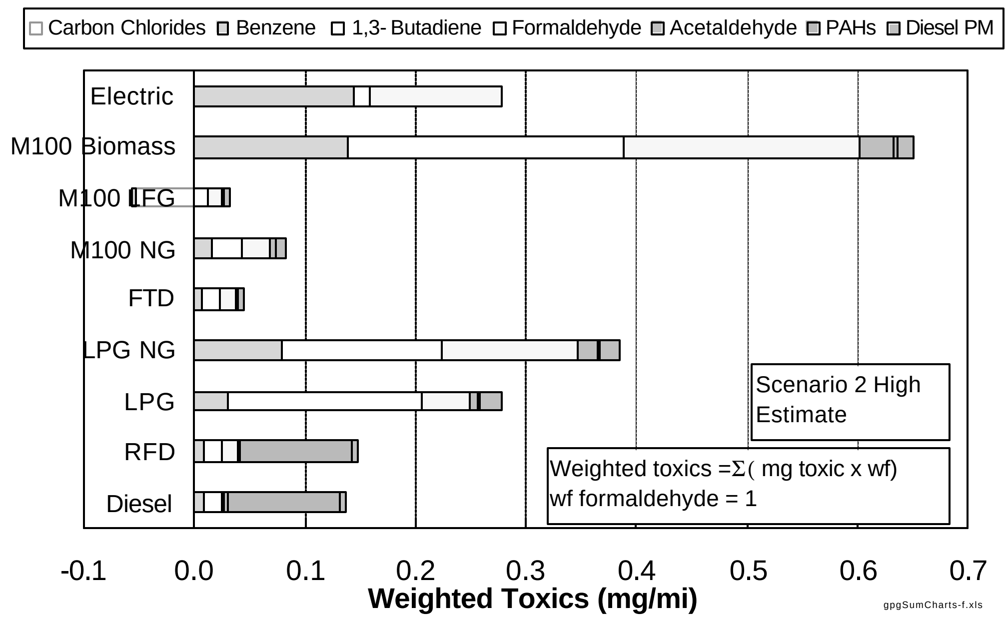
The toxics are compared on a weighted basis in Table 6-7 and Figures 6-6 and 6-7. The weighting factor is based on ARB's unit risk factors for toxic compounds. The weighting factor is the ratio of the unit risk factors normalized to formaldehyde = 1. The weighting factor is shown in Table 6-7 and multiplied by the mg/mi vlaues in Table 6-6. The primary source of toxics include diesel exhaust for hauling fuels, spilled diesel fuel, a source of PAHs, and power plant emissions. The toxic emissions are proportional to NMOG emissions with additional diesel PM from truck and ship hauling. Toxic emissions for LPG are notably high because of the smaller size of delivery trucks and higher diesel NMOG emissions per gallon. Emissions from M100 from biomass and LPG from natural gas are also high as these involve additional rail transport. As indicated in the discussion for NMOG, the toxics contribution is relatively low due to significant power plant activity outside the SoCAB.

Table 6-7: Emissions per mile driven, Scenario 2b

		Weighted Toxics (mg/mi)						
Compound	**Weighting**	**Diesel**	**RFD**	**LPG**	**FTD**	**M100 NG**	**M100 LFG**	**Electric**
Benzene	4.8	0.0081	0.0082	0.0117	0.0095	0.0144	-0.0024	0.0608
Carbon Chlorides	3.4	0.0000	0.0000	0.0000	0.0000	0.0000	-0.0475	0.0000
1,3- Butadiene	28.3	0.0147	0.0147	0.0687	0.0172	0.0259	0.0123	0.0075
Formaldehyde	1.0	0.0017	0.0124	0.0178	0.0146	0.0219	0.0104	0.0551
Acetaldehyde	0.5	0.0018	0.0018	0.0026	0.0021	0.0032	0.0015	0.0004
PAHs	1.0	0.0636	0.0638	0.0002	0.0002	0.0003	0.0001	0.0000
Diesel PM	50.0	0.0051	0.0051	0.0073	0.0063	0.0095	0.0051	0.000[a]
Total		0.095	0.106	0.108	0.050	0.075	-0.020	0.124

[a] Power plant PM is not diesel PM. If power plant PM were counted as diesel PM, weighted toxics would be 0.05 mg/mi higher

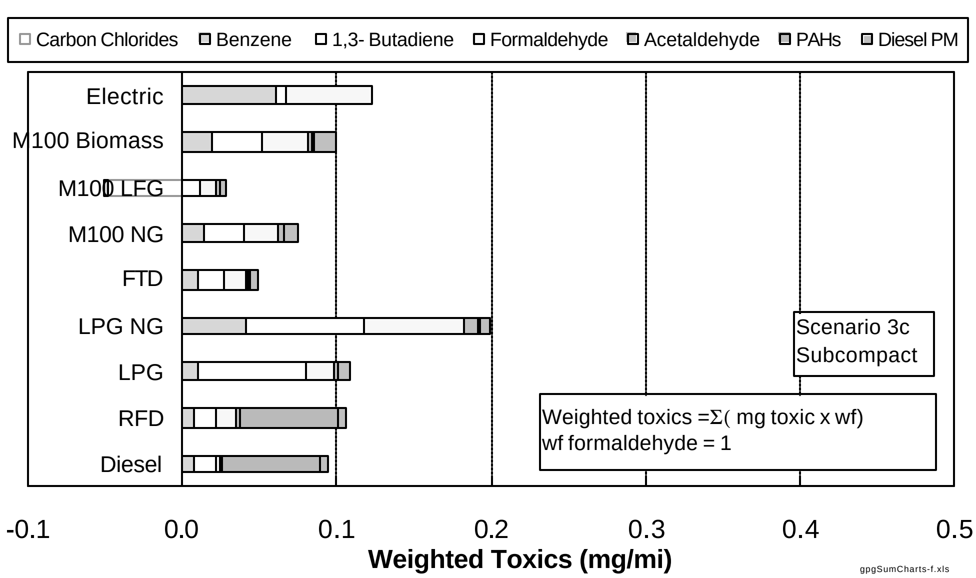
Figure 6-6: Weighted Toxics[a] Scenario 2b



[a]Marginal emission sources in SoCAB.

Source: Arthur D. Little

Figure 6-7: Weighted Toxics[a] Scenario 3C



[a]Marginal emission sources in SoCAB.

Source: Arthur D. Little

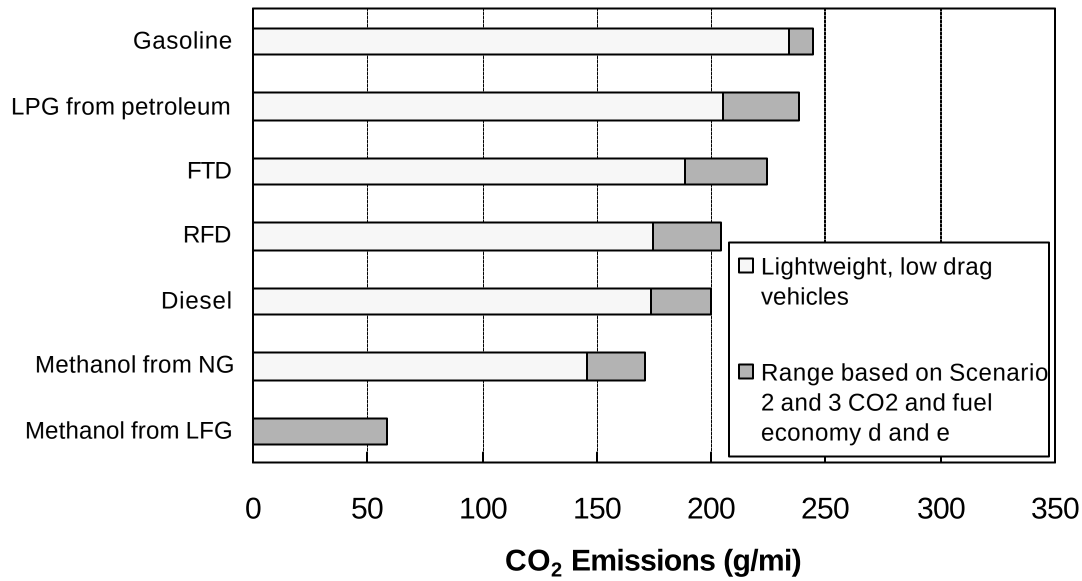
PM emissions were also calculated for the different fuel options for the purpose of determining weighted toxics. These results are included in Volume 2. One particularly interesting aspect of power plant emissions is PM levels which are not particularly well quantified. Source tests for power plants do not characterize the background PM emissions which could include pollen and road dust. New combined cycle power plants operate at very high excess air levels which would exacerbate the PM emissions. Power plant PM emissions were not included in the toxics calculation as only diesel PM is categorized as a toxic air contaminant by ARB. Only compounds that are determined to cause cancer or longterm harmful health effects in small doses are categorized as toxics by ARB.

Other components are not categorized as toxics. For example methanol, while a poison upon ingestion (acute toxicity) is not on the list of toxic compounds.

Figure 6-8 shows the global CO_2 emissions for the range of fuel economy and emission assumptions. Both vehicle exhaust and energy inputs for fuel production are included. This comparison shows the range of CO_2 emissions for light-weight cars, as these vehicles might be built in the future with the goal of reducing greenhouse gas emissions. The purpose of the comparison is to illustrate the potential for CO_2 reduction with different fuel choices for the light-weight vehicle options. Greenhouse gas comparisons are so strongly influenced by the gasoline baseline, so the comparison of light-weight vehicles to subcompacts is shown to illustrate the potential of high efficiency vehicles. The equivalent subcompact and light weight gasoline vehicle is also shown for comparison. Interestingly, weight reductions and drag improvements on the vehicle have as much of an impact on CO_2 emission reductions as do the type of fuel (except for biofuel options). More efficient hybrid diesel, LPG, or potentially fuel cell vehicles would result in further CO_2 reductions. Similarly, hybrid gasoline vehicles would have lower CO_2 emissions.

Producing methanol or FT diesel from gas that would otherwise be flared would result in a reduction in CO_2 emissions. The appropriate allocation of credits from reduced flaring depends partly on how national policies on greenhouse gas emission reductions are enacted and other factors. As there are differing views on whether to attribute the CO_2 emission reductions from flared gas to the end use fuel, the values shown in Figure 6-8 do not show a credit for reduced flaring of natural gas for methanol or FT diesel production.

Figure 6-8: Global CO_2 Emissions, Scenario 2, Marginal Fuel Sources



The potential for diesel, LPG, methanol, and electric vehicles to occupy different portions of the light-duty vehicle market affects their potential greenhouse gas and fuel cycle emission impacts. The fuel economy values in Table 5-9 illustrate the potential magnitude of this effect. The shift in vehicle fuel economy due to different market segments would be 10 percent for the vehicle mix that corresponds to DOE's market projections. For example, LPG vehicles are expected to displace larger gasoline vehicles with a fuel economy of 19 mpg. This result indicates that LPG vehicle would reduce greenhouse gases more than electric vehicles, which would displace smaller vehicles. Similarly, large diesel vehicles (SUVs for example) that displace large gasoline vehicles would reduce more greenhouse gas emissions and fuel cycle NMOG emissions than smaller diesel, methanol, or electric vehicles. Since the combination of fuel economy and well to pump fuel cycle emissions (on a g/gal basis) determine the total emissions impact, policy makers should be aware of the potential for emission reductions in all classes of vehicles. Clearly, lighter vehicles with high fuel economy would result in the lowest overall total greenhouse gas and fuel cycle emissions. However, customer demand has shifted towards larger vehicles, and policy makers may be more successful in focusing attention on emission reductions within a vehicle class than shifting consumer preference to smaller vehicles.

6.1 Analysis of Uncertainties

This section identifies the key uncertainties in fuel cycle emissions for each of the fuel options considered in this study, with emphasis given to the NMOG value. Several fuels are close the NMOG limit for the low fuel cycle emission portion of the PZEV allowance.

Figure 6-9 shows the key parameters that affect NMOG emissions for RFD. As the emissions as slightly lower for conventional diesel and FTD, these are not discussed. Spillage emissions are the largest source of marginal NMOG. The range in spillage depends upon fuel tank size and the refueling spillage rate. This emission factor for spillage is based on the average vehicle; however, the spillage per gallon increases as fuel tank size decreases. As discussed in Section 4.8, vehicles with improved fuel economy would have smaller fuel tanks and greater spillage per gallon. Based on limited data, fuel tank size is proportional to fuel economy; however, very efficient vehicles may tend to have somewhat greater range. Other parameters have a smaller effect on fuel cycle emissions. For RFD production, additional hydrogen is required for desulfuization. This hydrogen would be produced from reformed natural gas or refinery gas and NMOG emissions related to this process would be low on a per mile basis. Furthermore, in many instances, refineries may limit increases in hydrocarbon emissions in order to obtain approval for modifications related to fuel reformulation. For the subcompact vehicle analyzed for Scenario 3c, fuel economy assumptions have a relatively small impact on fuel cycle emissions as the EER values for diesel vehicles ranged from 1.21 to 1.37. NMOG emissions from tank trucks contribute relatively little on a g/mi basis. Fuel tank temperature also has a minimal effect on fuel cycle emissions as the vapor pressure of diesel fuel is low.

Figure 6-9: Uncertain in Marginal NMOG Emissions from RFD

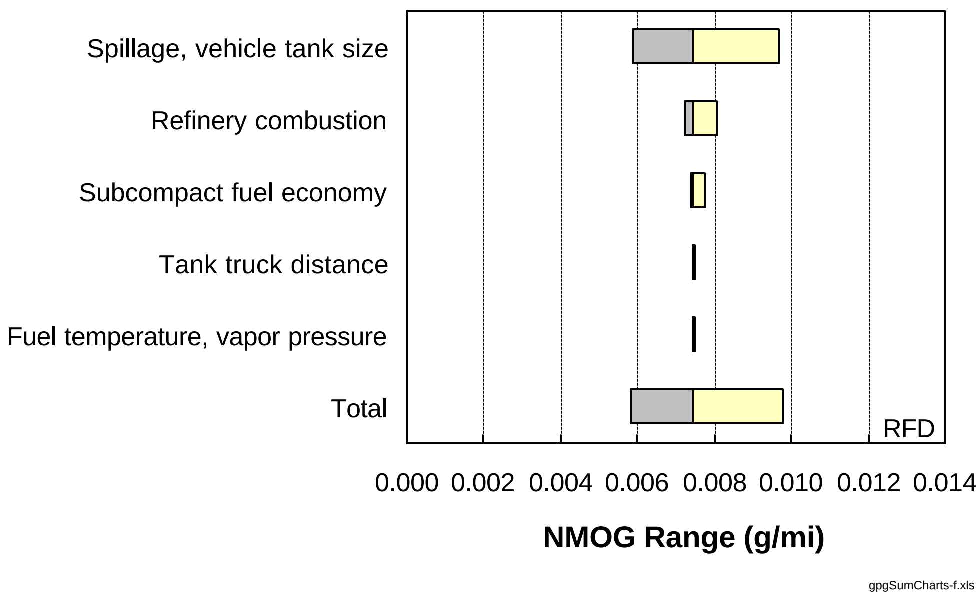
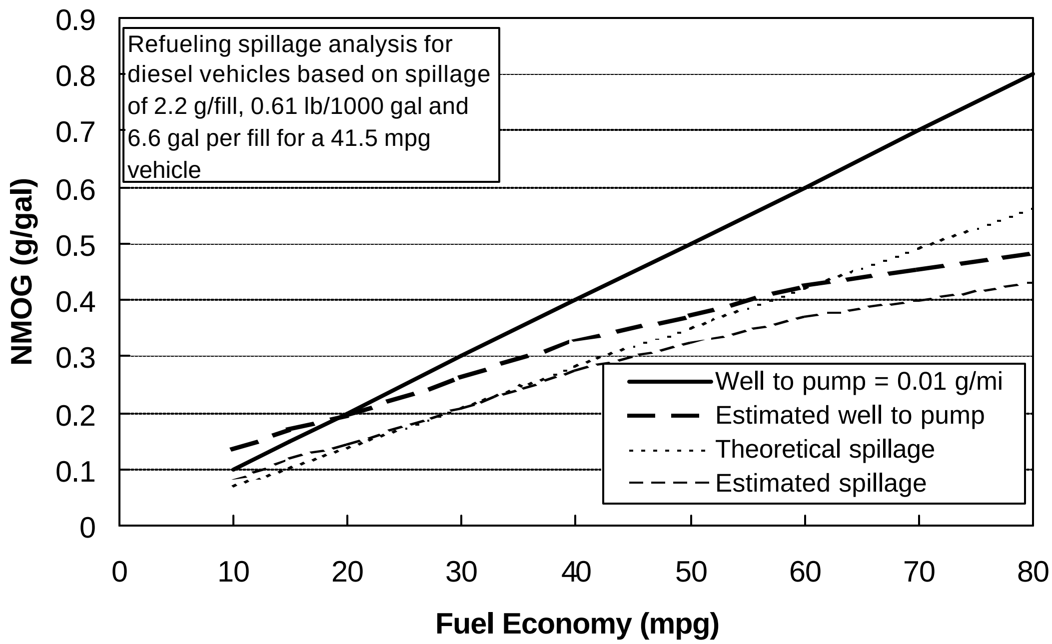


Figure 6-10 illustrates how spillage emissions increase with fuel economy. The spillage values that correspond to the subcompact and light-weight vehicles are shown in a g/gal basis. Both the spillage based on an estimated fuel tank size as well as spillage based on a fuel tank size that is proportional to vehicle fuel economy are shown. In addition to spillage, other fuel cycle NMOG emissions are added to the estimated spillage and indicated as well to pump emissions. The other fuel cycle emissions such as refueling vapor losses do not vary with fuel economy on a per gallon basis.

Figure 6-10: Effect of Fuel Economy on Marginal NMOG Emissions from Diesel Vehicles

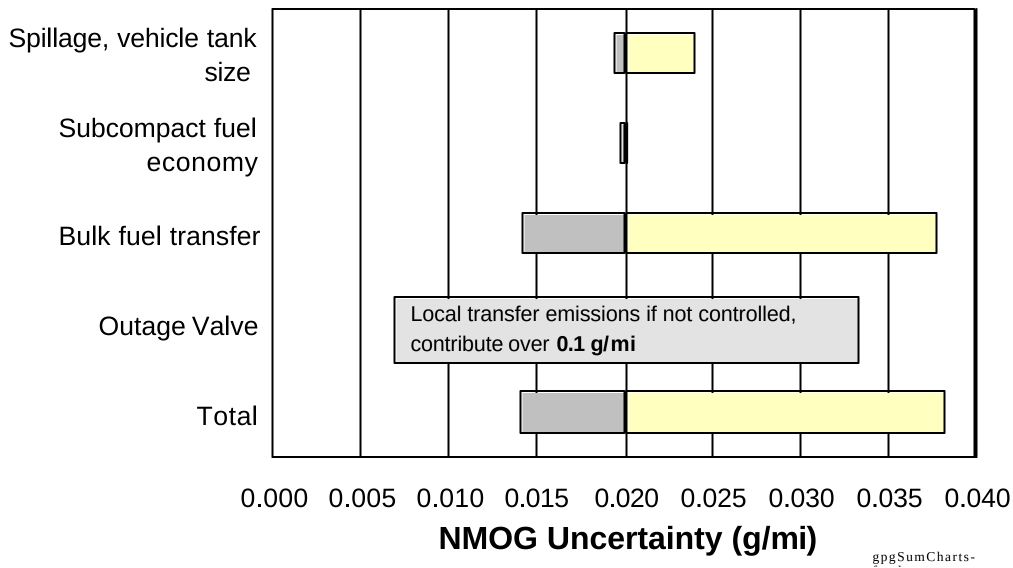


Analyzing fuel cycle emissions on a per gallon or well to pump basis is particularly meaningful as it illustrates the effect of fuel economy. Figure 6-11 also shows the allowable NMOG emissions that correspond to the 0.01 g/mi level. For fuel economy below about 18 mpg, constant fuel cycle emissions plus spillage result emissions above 0.01 g/mi.

The values in Tables 6-1 and 6-2 reflect well to pump emission fuel cycle emissions on a g/gal basis for subcompact cars. The basis for a low fuel cycle emission rating could be based on well to pump values and vehicle fuel economy with an adjustment for estimated spillage emissions.

Figure 6-11 illustrates the uncertainty in NMOG emissions for LPG vehicles. As was the case for diesel, spillage emissions are a significant uncertainty. Spillage emissions for LPG have the potential of being lower than those for liquid fuels, as these emissions correspond primarily to the trapped space in the fueling fitting. Accidental releases of several liters appear to be eliminated by the check valve effect in the fueling nozzle. However, in the case of LPG, outage valve losses represent a much larger contribution to NMOG emissions. All of the outage valve losses would need to be eliminated from tank trucks, service station tanks, 30,000 gal bulk tank trucks in order to reduce emission levels consistent with those in Scenario 3. Emissions from bulk fuel storage facilities remain a key uncertainty that should be investigated further.

Figure 6-11: Uncertainty in Marginal NMOG Emissions from LPG



The uncertainty in NMOG emissions for subcompact methanol powered fuel cell vehicles is illustrated in Figure 6-12. Again, spillage is a key uncertainty as these values were estimated from gasoline standards. Spillage volumes also depend upon fuel tank size, which was adjusted to reflect the methanol vehicle fuel economy. Another important uncertainty is the efficiency of vapor recovery. The same assumptions that apply to gasoline were applied to methanol and were adjusted for the lower vapor density of methanol. Light-weight vehicles with higher fuel economy result in NMOG emissions below 0.01 g/mi as illustrated in Figure 6-13. In the case of methanol, fuel cycle emissions other than spillage are a significant fraction of the total NMOG. Increasing fuel economy above 26 mpg or 52 gasoline equivalent mpeg results in NMOG below 0.01 g/mi. As a light-weight vehicle is more suitable for fuel cell operation, such methanol fuel cell vehicles, as analyzed under Scenario 3.2e, could be the choice of carmakers.

Figure 6-12: Uncertainty in Marginal NMOG Emissions for Methanol from Natural Gas

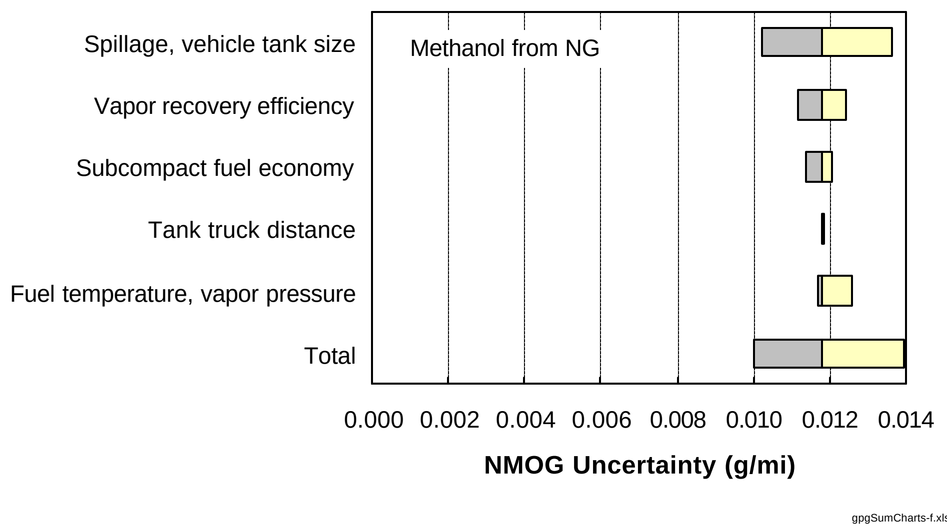


Figure 6-13: Effect of Fuel Economy on Marginal NMOG Emissions from Methanol Vehicles

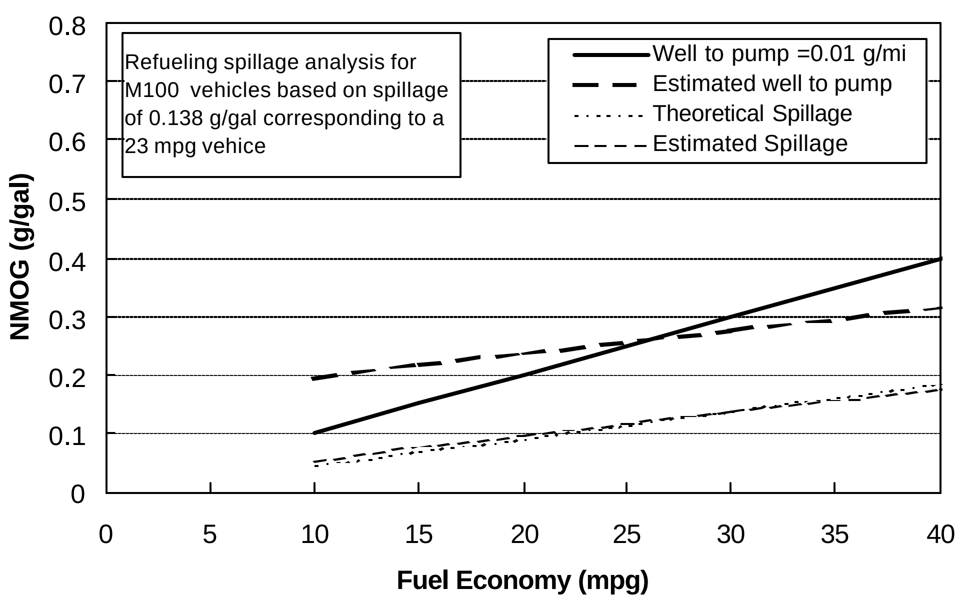
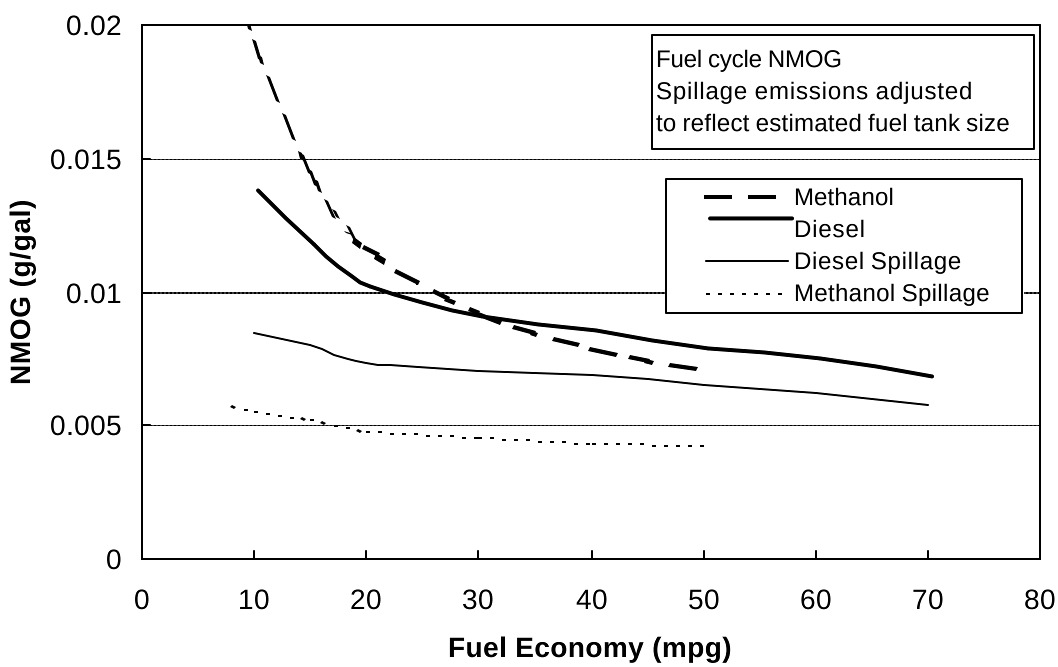


Figure 6-14 shows the fuel cycle NMOG emissions for diesel and methanol fueled vehicles on a g/mi basis. Since these results rise above 0.01 g/gal as fuel economy decreases, a requirement for meeting low fuel cycle emissions should be based on fuel economy as well as fuel choice. The effect of fuel economy on total NMOG emissions and estimated spillage emissions is also illustrated. Spillage emissions are relatively constant as vehicle fuel tanks are estimated to decrease in size as fuel economy increases. Larger fuel tanks could potentially reduce spillage emissions if consumers were to fuel their vehicles less frequently and add more fuel per fueling event. The actual effect would depend on consumer behavior and should be evaluated further.

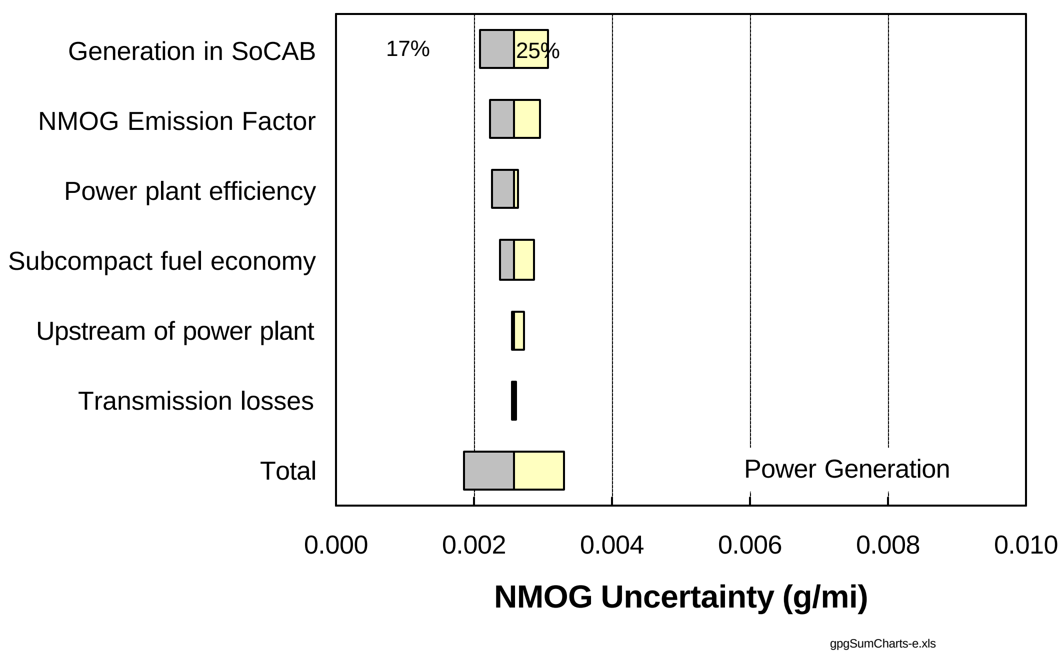
Figure 6-14: Effect of Fuel Economy on Marginal NMOG Emissions from Methanol Vehicles



The parameters that affect fuel cycle NMOG emissions for electric vehicle are different than those for liquid fuels. The NMOG emissions depend primarily on the generation mix, fraction of generation in the SoCAB, emission factor for NMOG from natural gas power plant, and power plant efficiency. Figure 6-15 illustrates the uncertainty in fuel cycle NMOG emissions from electric vehicles. CEC's modeling of power generation in California indicated that only 17 to 25 percent of the power for the SoCAB was generated in the SoCAB with about 75 percent of the power generated in California.

Limited data is found on the emission rates for natural gas power plants as the primary focus is on NO_x emissions. The uncertainty in the NMOG emission rate corresponds to the range in emission factors for boiler and turbine power plants. The actual NMOG fraction from these plants may require further study. Source tests for power plants are typically performed with total hydrocarbon (THC) analyzers, and speciation data that would determine the fraction of non-methane hydrocarbons is limited. In any event, the NMOG emissions from natural gas power plants result in low emission on a g/mi basis.

Figure 6-15: Uncertainty in Marginal NMOG Emissions in the SoCAB from EV Operation



Fuel economy, power plant efficiency, and transmission losses play significant roles in CO_2 from EV operation, as a 20 percent difference in this pollutant is significant. However, because total NMOG from EV operation is very low, variations in these parameters have a limited effect on total NMOG. The sensitivity of power plant efficiency on CO_2 emissions is a significant issue. The CEC analysis indicates an energy consumption of 8700 Btu/kWh while representatives of the utility industry indicate this value should be below 7000 Btu/kWh (HHV basis). A key parameter in the marginal heat rate for EV operation is the total generation capacity. The CEC's analysis is based on future reserve margins being lower than historical levels as deregulation would tend towards operating costs. However, low reserve margins also result in pressure on power prices. In practice, more power generation capacity will be required in California. Increased generation capacity would tend to increase the number of new high efficiency power plants.

The effect of the late year 2000 power shortage in California on marginal emissions has not been analyzed in detail. However, one interesting consequence of high power prices was the willingness of Northwest aluminum producers to sell rights to hydroelectric power and shut down aluminum production. This effect illustrates the complexity of assessing marginal sources of power generation. Even if additional power were made available from aluminum producers, the consequences of this economic shift would also result in other CO_2 emissions. An important factor in assessing the efficiency of power generation and related CO_2 emissions is the fate of older power plants, the installation of new generation capacity, and the likely reserve margins that would be maintained in the future. At this time, it is not possible to accurately predict future generation expansions.

Other pollutants are also produced from power generation. NO_x emissions are limited by the RECLAIM program in the SoCAB. New power plants in California are required to obtain NO_x offsets. Additional offsets may be difficult to achieve from conventional stationary sources and mobile offsets could be used as more generation capacity is added in California.

Power plants are also a source of particulate emissions (see Appendix E). Particulate levels can be about half the level of NO_x. However, background particulate levels are not taken into account as part of these measurements.

7. Conclusions

Fuel-cycle emissions were evaluated in the context of marginal emissions associated with marginal alternative fuel consumption or gasoline displacement. A moderately small use of alternative fuels would displace gasoline that would be imported into the SoCAB or allow for additional exports from the SoCAB, while a more aggressive alternative fuels penetration may lead to a reduction in refinery output. Small increments of alternative fuel use would displace emissions from fuel hauling, vehicle fueling, and possible marine vessels used to import refinery blending components. On a small scale, other market conditions will influence refinery emissions more substantially than gasoline displacement due to alternative fuel use, leaving the refineries in the SoCAB operating at capacity. Many alternative fuels would be produced outside the SoCAB. Their marginal emissions correspond largely to fuel trucking or distribution and local vehicle fueling. The marginal assumptions in this study are consistent with alternative fuel use on the scale of vehicles that would meet the PZEV requirements. A fuel demand consistent with 1 percent of the vehicle population was examined. These marginal results would be appropriate with fuel demand in the foreseeable future.

Electricity for EVs in use in the SoCAB is generated in the basin, the rest of California, and outside of California. Marginal emissions from power generated in the SoCAB are limited by several factors. Existing facilities in the SoCAB could not increase emissions beyond current permit levels, and new facilities would need to buy offsets. Power plants in the SoCAB are subject to RECLAIM that provides a cap on power plant NO_x emissions for each utility. If a utility is above its RECLAIM limit, it can install SCR on additional power plants or purchase NO_x offsets. If a utility is already at its emission cap or in a position where it needs to purchase offsets with respect to SoCAB RECLAIM, any incremental power generation for EVs will result in no additional NO_x emissions in the SoCAB. Power generation requirements for baseline power and for EVs were evaluated for several different power generation scenarios. The generation scenarios had about a 20 percent impact on NMOG emissions, which is not noticeable at the low levels that would occur in the SoCAB. Generation assumptions did, however, have a similar impact on CO_2 emissions. The assumption in this study is consistent with marginal power being generated from gas fired plants with a net efficiency from 42 to 48 percent. These efficiency assumptions are consistent with new generation capacity that is being constructed in California and the declining age of the existing generation mix. Since the number of new plants is subject to a number of economic and regulatory factors, the precise mix of future plants is difficult to model.

Marginal NMOG emissions from EVs are less than 0.01 g/mi. This result is based on natural gas power generation on the margin with over 70 percent of the generation outside of the SoCAB. If all the power generation occurred in the SoCAB, NMOG emissions from EVs would be 0.01 g/mi.

The time of day for EV charging would affect the generation mix. The modeling of power dispatch was performed for primarily nighttime generation. On-peak generation probably has a limited effect on NMOG emissions in the SoCAB as much of the power in the basin would be produced from natural gas and a the majority of the power would be produced outside the SoCAB.

Marginal NMOG emissions for diesel, RFD, and FTD are below 0.01 g/mi for all but the heaviest vehicles with fuel economy below 20 mpg. The subcompact and light-weight diesel fueled vehicles that were specifically analyzed in this study and considered comparable to electric vehicles resulted in NMOG emissions below 0.01 g/mi.

Marginal NMOG emissions from M100 vehicles drop below 0.01 g/mi for vehicles with fuel economy above 27 mpg (or 54 miles per equivalent gasoline gallon). A light-weight high efficiency would have NMOG emissions below 0.01 g/mi. While there is some uncertainty in the magnitude of spillage emissions and evaporative emission losses, it is unlikely that the fuel economy for a typical subcompact would be high enough to achieve this low NMOG level. Additional vapor controls are assumed to be implemented LPG for Scenario 3 which would also result in fuel cycle NMOG. However, at this time, no regulatory measures are in place to control emissions from LPG truck transfers, and a wide variety of venting losses would need to be controlled to achieve emissions below 0.01 g/mi.

CO_2 emissions from EVs would be 50 to 75 percent of those from a comparable gasoline vehicle. This comparison is for vehicles that are similar except for range, which the customer presumably trades off against home charging and other vehicle attributes. These CO_2 values apply to a projected generation system with a substantially higher reserve margin than in 2001. The primary factor that affects CO_2 emissions is vehicle weight, drag coefficient, and other factors that affect the vehicle's road load. Existing diesel technology results in CO_2 emissions that are 75 percent of those of a gasoline vehicle. Hybrid operation would result in lower CO_2 emissions but the fuel economy potential of these vehicles was not studied by the project advisory committee. The primary conclusion that marginal NO_x and NMOG would be very low for diesel powered vehicles holds true for both conventional and hybrid designs.

CO_2 emissions from a methanol fuel cell vehicle would also be less than 75 percent of those from a comparable gasoline vehicle. However, as the fuel economy and light-weight characteristics of vehicles vary, the results in this study should be considered just a reflection of the potential emission reduction. Actual CO_2 reductions depend on vehicle fuel economy, and policy makers can evaluate CO_2 from the vehicle's fuel economy and well to pump emission rates (which include the vehicle exhaust portion). Methanol can also be produced from flared gas, or CO_2 can be added to the methanol production to improve efficiency. The effect of these options was not analyzed in this study. Reductions in flaring may not be uniquely attributed to methanol vehicle operation. Methanol produced from biomass sources such as landfill gas results in almost no net CO_2; however, the quantities of methanol that would be produced from such sources appear limited in the near term.

7.1 Emission Policy Considerations

The results of this study indicate that fuel spillage is a dominant source of fuel-cycle emissions. Once refueling vapor emissions are eliminated or are very low as in the case of diesel, refueling spillage becomes the dominant source of NMOG. Spillage emissions (per gallon) in general tend to drop as fuel tank capacity is increased. For some vehicle technologies, fuel tank size will increase with lower fuel economy in order to maintain a constant range. While the consumer may not always utilize the full fuel tank capacity, the connection between the spillage related NMOG on a g/mi basis and fuel economy is weak.

One of the most significant questions concerning marginal fuel-cycle emissions is how to treat fuel economy. Several options for allowing credit for low fuel-cycle emissions are summarized below.

7.1.1.1 Base Low Fuel-Cycle Allowance on Actual Vehicle Fuel Economy

ARB could allow low fuel-cycle PZEV credits based on a vehicle's actual fuel economy weighted over the CAFE mix of city and highway driving. This approach has the advantage of not being reliant upon an assessment of vehicle fuel economy. Manufacturers would be incentivized to make vehicles more fuel efficient and lighter. ARB could publish a fuel-cycle rating for each fuel on a g/gal basis that the manufacturer could then divide by the vehicle fuel economy. Manufacturers could also improve the fuel-cycle emission score by increasing fuel tank capacity to reduce spillage emissions per gallon of fuel.

The disadvantage of this approach is that it primarily favors small passenger cars, while trucks and SUVs are a growing part of the LDV mix. A small SULEV would likely displace the sale of another small car. Another disadvantage of this approach is that smaller vehicles balance out larger vehicles in the CAFE calculation.

7.1.1.2 Base Low Fuel-Cycle Allowance on Assessment of Vehicle Fuel Economy

ARB could certify fuels based on the results of this study. This approach recognizes that a variety of vehicles will be sold in the market and this study takes into account the likely effect of vehicle fuel economy. If the projected vehicle fleet fuel-cycle emissions were below or near 0.01 g/mi then the fuel would qualify. This approach would allow large vehicles to qualify for the low fuel-cycle allowance and would not provide an additional incentive to improve fuel economy or reduce CO_2 emissions. A large vehicle meeting SULEV exhaust would provide significant fuel-cycle emission reductions, primarily by eliminating refueling vapor emissions.

7.1.1.3 Base Low Fuel-Cycle Allowance on Vehicle Size Category Bins

In order to incentivize highly efficient vehicles and not bias the low fuel-cycle allowance towards smaller cars, ARB could provide minimum fuel economy requirements for each fuel and vehicle size category. This approach would allow manufacturers to make a highly efficient large vehicle and reduce fuel-cycle emissions when compared to other vehicle types.

7.2 Recommendations

Based on the information found in this study, we make the following recommendations for further study.

1. Evaluate the well to pump and per mile fuel cycle emissions from gasoline-fueled vehicles. A variety of reviewers expressed interest in these values, and they are readily available from the methodology and assumptions used in this study.

2. Include a fuel economy element in policies that are affected by fuel cycle emissions. For example, in order to assure a 0.01 g/mi fuel cycle NMOG emission rate, base this requirement on g/gal value for each fuel (well to pump) values and actual fuel economy.

3. Measure emissions from new combined cycle power plants especially particulate, hydrocarbons, and hydrocarbon speciations to determine NMOG and toxics. Assess the effect that background emissions have on projected and net power plant emissions.

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